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Power Pooling in the Western Region

Federal Energy Regulatory Commission
Office of Electric Power Regulation
Washington, DC 20426

February 1981

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Power Pooling in the Western Region

Prepared by the
Western Regional Task Force

For the
Federal Energy Regulatory Commission
Office of Electric Power Regulation
Washington, DC 20426

February 1981

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FOREWORD

This report is one of five regional reports prepared by task forces as part of the Federal Energy Regulatory Commission (FERC) power pooling study under the provisions of Section 205(b) of PL 95-617, the Public Utility Regulatory Policies Act of 1978 (PURPA). The Act directs the Commission to conduct a study of power pooling and report its findings to the President and Congress. The purpose of the study is to examine "the opportunities for (a) conservation of energy, (b) optimization in the efficiency of use of facilities and resources, and (c) increased reliability through power pooling arrangements."

The regional task forces were formed after consultations with industry and regulatory representatives. Each member of the five regional task forces served primarily as an individual, contributing personal knowledge and interpretations, and provided information on industry activities and problems on the basis of this expertise.

The regional reports reflect the work of the task forces in addressing the characteristics and problems of coordinated electric power operations in each region. The purpose of the task forces was to assist in developing a regional-specific factual understanding of the development, status, problems, plans, benefits, costs, industry and regulatory views, and other significant aspects of power pooling in the region.

In addition to the regional task force reports, which are primarily descriptive, a separate report is being submitted to the President and Congress containing an overall assessment of the status of power pooling and the prospects for increased application of power pooling in the United States by the electric utility industry. This assessment and report is be based in part on the reports and proceedings of the task forces.

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NOTE: Although the individual members of the task force are in basic agreement with the contents of the report, each does not necessarily agree with all of the comments or interpretations in the report.

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EXECUTIVE SUMMARY

This report reviews the current status of electric power system coordination and power pooling in the Western Region. It discusses benefits, identifies issues and problems that are impediments to increased pooling, and assesses prospects and possibilities to conserve energy and to optimize efficient use of facilities and scarce resources through power pooling arrangements.

The Western Region is an area comprising fully one-third of the contiguous Jnited States. The Western Region coincides with the United States' portion of the Western Systems Coordinating Council (WSCC), the largest, geographically, of the nine regional councils of the National Electric Reliability Council. Electric utilities in the Western Region serve all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington, and Wyoming, and parts of Montana, Nebraska, New Mexico, South Dakota, and Texas. Key characteristics of the Western Region are extremes in climate, precipitation, and population density; the concentration of indigenous fuel resources in sparsely populated States; great distances between load centers and power generating sources; and a high percentage of hydroelectric generation, particularly in the Pacific Northwest and northern California. For purposes of this report, the Western Region is divided into four subregions: the Northwest Power Area (NWPA), the Rocky Mountain Power Area (RMPA), the Arizona-New Mexico Power Area (AZNMA), and the California-Nevada Power Area (CANVA). (See Figure 1, Chapter 1.) These subregions are interconnected by an extensive regional bulk power transmission network permitting the entire region to operate in a coordinated fashion.

The extent of pooling arrangements in the Western Region ranges from groups with formal organizational structures, permanent staffs, and well-defined functions to informal arrangements between two or more utilities to take advantage of specific opportunities for economic savings or to address specific operational problems on a coordinated basis. Many of these arrangements cross subregional boundaries permitting utilities to take advantage of diversity that exists between subregions.

The pooling arrangements between utility systems in the Western Region are yielding economic benefits through:

- Coordinated planning and construction of large, jointly owned generating units and EHV transmission lines to take advantage of economy of scale

- o The scheduling of power interchanges between utilities both within and outside of subregions for more efficient and economical use of generating resources, for exploiting diversity among resources and loads, for minimizing operating costs, and for conserving oil
- o Coordinating the operation of hydroelectric generating plants to maximize their firm load-carrying capability
- o Sharing of reserve capacity to reduce capital and operating expenditures
- o Providing emergency assistance, scheduled outage assistance, and short-term storage of energy to reduce capital and operating expenditures
- o Sharing the use of transmission facilities and wheeling of power for others to reduce capital expenditures

As a general observation of the task force, good planning and operating coordination both exist in the Western Region, though they exist principally through a multiplicity of lower level coordinating arrangements. The current principal impediment to increased regional coordination lies, therefore, in identifying additional benefits with sufficient certainty to justify the substantial expenditures required to realize the benefits. If the economics of increased coordination justify new facilities, then the potential exists for regulation to become the principal impediment. The more significant regulatory impediments identified by the task force are the following:

- o The uncertainty of regulation, which impairs the ability of pooling participants to proceed with needed bulk facilities.
- o The attitude of individual States, which discourages out-of-State utilities from participating in jointly sponsored generation and transmission projects.
- o Regulatory action (or inaction) and the administration of environmental laws that result in facility cancellations and delays.

Actions that the task force deems necessary to eliminate or reduce impediments include the following:

- o Better ways should be developed to evaluate the real, long-term incremental benefits of power pooling.
- o An effective program should be instituted to better inform elected officials, regulatory agencies, and the public about the salient facts of regional bulk power supply.
- o State regulators should meet on a regular basis to discuss and to address, to the extent possible, interstate bulk power facilities siting issues and regulatory impediments.
- o In States where regulation of the utility industry is dispersed among several single-purpose agencies, the States should review lines of communication between those agencies to ensure that effective communication is being maintained.

- Federal regulators should facilitate the timely construction of bulk power facilities.
- State regulators should provide a reasonable utility rate base and return necessary to support the construction of regional bulk power facilities and further integration.[1]

The prospects for increased regional coordination include the following:

1. In NWPA
   Completing and implementing a thermal coordination agreement to spread the impact of thermal outages among participants, to provide the most economic thermal resources operation, and to protect the regional adequacy and reliability of the combined hydroelectric and thermal system.
2. In RMPA
   Expanding the functions of the Inland Power Pool to extend the operating function and to include planning functions. The Inland Power Pool is expected to become the major focus for coordination in RMPA and AZNMA.
3. In AZNMA
   Utilities will continue to seek membership in an expanded Inland Power Pool in order to enhance bulk power supply economy.
4. In CANVA
   The four major California utilities will seek additional reliability and economic benefits by increasing coordinated planning and operations above current levels. Real time incremental cost data will be telemetered between three California Power Pool companies to facilitate additional economy energy transactions. Further studies will be undertaken to identify other specific actions that may be warranted. The major utilities are projecting the installation of large baseload generating units as joint projects with smaller utilities in CANVA and adjacent States.
5. Regionwide
   Studies are in progress on three alternative proposals to supplement the capability of the present Pacific Northwest-Southwest intertie to permit a greater interchange of power and energy between the Pacific Northwest and the Pacific Southwest. Studies are now underway to further explore the potential for increasing power exhanges between the western United States and British Columbia and Alberta. Thirty-one member systems are participating in WSCC's oil conservation

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[1] In the view of task force members representing State regulators, regulation of the rate base and rate of return has not been an unreasonable impediment to the construction of needed regional bulk power supply facilities.

program to ensure that oil-burn requirements are being minimized. The WSCC Operating Committee is studying the benefits of continuing oil conservation reporting. Under the auspices of WSCC, and on a voluntary trial basis, utilities in the four subregions will participate in an energy brokering system to ensure that all potential money saving enconomy energy interchanges are consummated. An interest in expanding generation and transmission planning to include the entire Northwest Power Area has been indicated. Even greater expanded geographic planning could be a possibility if such an expansion were implemented through WSCC.

COORDINATION IN THE NORTHWEST POWER AREA

NWPA is the largest of the four subregions of the Western Region in both geographical area and generating capability. Forty-three generating utilities in NWPA include two Federal agencies whose power is marketed by the Bonneville Power Administration (BPA). This report describes the following seven coordinating groups, which operate in the area:

1. The Northwest Power Pool (NWPP)
2. Pacific Northwest Coordination Agreement (PNCA)
3. Mid-Columbia Hourly Coordination Agreement (MCHA)
4. Intercompany Pool (ICP)
5. The Pacific Northwest Utilities Conference Committee (PNUCC)
6. The Public Power Council (PPC)
7. The Public Generating Power Pool (PGPP)

The membership of these groups is given in Chapter 3.

THE NORTHWEST POWER POOL (NWPP)

NWPP is an informal organization that has functioned in the NWPA since 1942. After the war, the organization continued on a voluntary, informal basis--a confederation of autonomous electric systems without a central authority. The primary purpose of the group has been to deal with operating problems related to interconnected operation, including interchange accounting, generation and voltage control practices, operating reserve, and emergency actions.

The organization functions through an operating committee (OC) consisting of 17 U.S. members and 3 Canadian, one representative from each participating system. Unanimous agreement is required to implement committee decisions. The OC maintains a staff of engineers and clerical personnel which is designated the coordinating group (CG). The group is delegated no authority but acts in a consulting capacity to the OC. It assembles and publishes the results of many coordinated activities such as the annual

operating program, the annual operations reserve, the pool underfrequency load shedding program, power and reactive tests of actual operation, maintenance scheduling, and headwater reservoir payments. It also makes operating studies, prepares operating programs, and conducts the studies and system monitoring prescribed by the Pacific Northwest Coordination Agreement. Finally, in addition to certain administrative duties the CG collects and prepares data for submittal to other groups such as WSCC, the operating committee and engineering committee of NERC, and acts as an informational clearinghouse for the entire group.

Utilities in the NWPA that are dependent on the Columbia River hydroelectric development have entered into the Pacific Northwest Coordinating Agreement (PNCA) and the Mid-Columbia Hourly Coordination Agreement (MCHA); seven major investor-owned utilities, operating throughout the NWPP have formed the Intercompany Pool (ICP).

PACIFIC NORTHWEST COORDINATION AGREEMENT (PNCA)

PNCA is a long-term contract providing for coordination of the seasonal operation of resources, particularly hydroelectric resources. It formalizes established NWPP practices and principles in binding terms and establishes rights, obligations, and procedures associated with the terms of the U.S.-Canada Columbia River Treaty that became effective in 1964. All signatories to the PNCA control power generating facilities within the NWPP. The agreement calls for the coordinated operation of the generating facilities, transmission facilities, and reservoirs of all the parties to achieve as closely as possible the capability of a single system to meet firm energy and peakload requirements. It establishes a contract committee, composed of one member from each party, to make studies and plans as required to implement the terms of the agreement. The committee is delegated no authority but receives technical support from the coordinating group of the NWPP. The agreement contains a specific method of computing poolwide reserve generating capacity, based on probability calculations and on the standard of 1 day loss-of-load in 20 years. It also contains a specific method of allocating the pool reserve to members, based on the ratio of reserve that would be required independently by each member to the sum of such values, computed by the probability method used to establish pool reserve.

A detailed method is provided to determine the firm capacity of each member's generation resources. The agreement contains a series of rates for sale and exchange of capacity and energy as follows:

- interchange energy imbalances for the sale of surplus energy
- interchange energy service for the return of borrowed energy
- interchange capacity imbalances for the sale of nonfirm capacity

- holding interchange energy service charge for energy received by a party to which it is entitled to maintain water in its reservoirs
- stored energy service charge for the storage of energy in the reservoir of another member
- transmission service charge for third-party wheeling
- special storage arrangements for the return of energy from storage
- transfers for storage to avoid spilling water

Long-range planning of new resources is not covered by the agreement. Because the agreement was developed before any dependence on large thermal generating plants, it does not provide for coordination of the operation of such plants.

MID-COLUMBIA HOURLY COORDINATION AGREEMENT (MCHA)

MCHA provides for the dispatch of seven mid-Columbia hydroelectric projects in a manner simulating operation that would result if all plants were owned and operated by a single entity.[2] The parties agree to coordinate the operation of the projects to obtain increased power and energy from the total system of projects and to provide flexibility and ease of scheduling generation through a method of centralized coordinated scheduling and the use of composite scheduling and accounting procedures. Each owner and purchaser retains all rights and obligations as though uncoordinated, and shares in the benefits of the coordinated operation depending on where and to what extent they occur.

INTERCOMPANY POOL (ICP)

The seven privately owned systems in the region coordinate their operations and generation expansion plans through the ICP to install the most economical and reliable units. The ICP Agreement establishes a committee, which is made up of one representative of each member, to direct all pool activities. A unanimous vote is required to implement any committee decision. Annually, a planning subcommittee prepares a report covering the next 10 years that projects the pool load, generation, and transmission plans, based on members' current data. The committee is authorized to sponsor research and development projects, and conservation and load management studies.

The agreement provides for the sharing of installed and operating reserves by the members. The committee determines the

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[2]The seven plants are: Grand Coulee, Chief Joseph, Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids.

total pool-installed reserve requirement by using loss-of-load probability techniques. The present pool planning standard is 1 day loss-of-load in 20 years. The method and planning standards are the same as used in the Pacific Northwest Coordinating Agreement. Total pool reserve is allocated to each member by using the same loss-of-load probability, but not more than 17 percent reserves if it has no unit serving more than 25 percent of its peakload. Each pool member must maintain operating reserves equal to 5 percent of hydroelectric load and 7 percent of thermal load. No capacity deficiency penalty is provided.

The agreement specifies methods of allocating among members any nonfirm energy made available by the BPA, and any nonfirm capacity and energy made available by any member. Members may use transmission facilities of others at no charge for transfer of operating reserves, emergencies, and stored energy, and for other transfers at 0.25 mil per kWh. Maintenance schedules of the members are coordinated by the committee.

THE PACIFIC NORTHWEST UTILITIES CONFERENCE COMMITTEE (PNUCC)

First established in the mid-1940's, PNUCC was comprised of both investor-owned and publicly owned electric utilities which, for the most part, either owned or had an interest in generating facilities. PNUCC worked with various agencies in the United States Government on matters relating to the planning, construction, and coordinated development of Federal projects associated with the United States Columbia River power system. It also worked with the Federal agencies to present to Congress the views of the non-Federal electric utility industry in the Pacific Northwest relative to various Federal appropriations affecting the power supply of the NWPA. A policy committee, consisting of representatives of all public agencies, direct service industries, and investor-owned utilities with an interest in PNUCC activities which may or may not be members of the PNUCC organization, has since been formed, along with an executive and system planning committee.

One of PNUCC's main activities during the last few years has been the preparation of the NWPA-West group forecast, which is a comparison by the Loads and Resources Subcommittee of the region's total electric requirements and its total electric resources.

THE PUBLIC POWER COUNCIL (PPC)

PPC, which was formed in 1966, comprises 113 Bonneville Power Administration preference customers, including public utility districts, municipalities, and cooperatives. As the power planning and coordinating organization for all of these preference customers, PPC promotes the common power supply interest of its members and plans with other groups and utilities to meet future power needs for the Pacific Northwest.

PUBLIC GENERATING POWER POOL (PGPP)

PGPP is an organization of seven consumer-owned electric utilities formed to make the most efficient use of power resources and facilities owned jointly and severally by the members. Members exchange information regarding power supply, system load, and forecasted area weather data on a regular basis.

The participating member utilities are the Eugene Water and Electric Board, PUD No. 1 of Douglas County, PUD No. 1 of Chelan County, PUD No. 1 of Cowlitz County, PUD No. 2 of Grant County, the City of Tacoma, and the City of Seattle.

COORDINATION IN THE ROCKY MOUNTAIN POWER AREA

RMPA is defined as the general geographic area that includes all of Colorado and parts of Wyoming, Nebraska, and South Dakota. The area is extremely rich in fossil fuel resources with several minemouth generating stations presently being developed. Much of the generation is located at great distances from major load centers with the Rocky Mountains imposing physical limitations on locations of transmission lines to connect these remote resources to the load. The area has a generation mix of about 56 percent thermal and 33 percent hydroelectric.

Three power pools operate in the area--the Inland Power Pool (IPP), the Rocky Mountain Power Pool (RMPP), and the Colorado Power Pool (COPP). The Inland Power Pool and the Colorado Power Pool are formal pools; the Rocky Mountain Power Pool is an informal, noncontractual organization. The members are listed in Table 9, Chapter 4.

ROCKY MOUNTAIN POWER POOL (RMPP)

RMPP is an informal, noncontractual association of 14 electric systems (public, private, and Federal systems) operating in Colorado, Wyoming, and parts of Montana, Utah, Nebraska, and South Dakota. The pool resolves daily and seasonal operating problems among members and with other interconnected pools and groups. Daily coordination on operating matters is accomplished through discussion by pool operators. An operating committee is appointed from the operating companies with committee officers who are elected annually. The committee's primary function is to coordinate the activities of the pool regarding operation, including (1) coordination of generation maintenance schedules, (2) underfrequency load shedding, (3) relaying, (4) scheduled outages of key transmission facilities, and (5) investigation and analysis of disturbances. RMPP does not have central planning or central dispatch functions and does not have a staff.

THE COLORADO POWER POOL (COPP)

COPP was formed under an October 1956 agreement, and operates under the direction of an operating committee consisting of one appointee from each of the member systems. The operating committee establishes pool operating rules and procedures, including the determination of each party's system capabilities. The agreement States that its primary purpose is standby service and reserve capability. Each party provides 8000 kW of reserve generating capability that it will furnish during scheduled and unscheduled outages. Parties that do not maintain the reserve capacity must pay $1 per month for each kilowatt of deficiency. If the deficiency continues for 4 or more years the cost of deficiency capacity rises to $2 per kW-month. Deficiency payments are divided equally among the excess parties. The agreement states that each party may make use of the transmission facilities of any of the parties for wheeling of power and energy, to be arranged under separate agreements and under schedules that are administered by the operating committee. When energy is furnished under the pool agreement, it is priced at fuel cost plus 5 mills per kWh. Inadvertent energy is returned in kind. Purchase of firm power and energy between pool members is arranged under separate agreements. Accounting for energy exchanges is performed by the Public Service Company of Colorado.

THE INLAND POWER POOL (IPP)

IPP members operate generation and transmission systems in Arizona, Colorado, New Mexico, Wyoming, and parts of Utah and Nebraska. IPP was formed by a May 6, 1974 agreement, which provides for an operating committee made up of one representative appointed by each member to administer the pool. The committee establishes the working practices of the pool such as the procedures and standards for determination of costs related to pool transactions, load shedding procedures, and other related operating matters. Committee action is taken by agreements signed by each committee member.

The IPP agreement notes that the members agree that it is prudent to plan for an installed reserve margin meeting a reliability criterion of 1 day loss-of-load in 10 years, but no capability obligation is imposed. The operating committee establishes the operating reserve responsibility for the pool, which currently is the larger of (1) 7 percent of the pool load furnished by thermal generation plus 5 percent of the load furnished by hydroelectric generation, or (2) the largest single generation unit plus 1 percent of the combined pool load. Monthly pool reserve is allocated to each member based on the ratio of 25 percent of monthly peakload plus 100 percent of the largest outage contingency for a thermal-electric system and 71 percent of the largest outage

contingency for a hydroelectric system of each party to the sum of the values for all parties. Capacity deficiencies are computed daily and charged for at $0.045 per kW-day. Deficiency payments are distributed among the excess parties in proportion to their excess capacity to the total of such capacity. The pool provides for emergency assistance on request for up to 10 days, after which it is classified as scheduled outage. Payment is by return in kind at a rate of 1.5 kWh for each kWh furnished to the requesting party. The pool also provides for the furnishing of scheduled outage power and energy at $0.045 per kW per day plus the return of an equal amount of energy.

COORDINATION IN THE ARIZONA-NEW MEXICO POWER AREA

AZNMA includes, in general, all of Arizona, most of New Mexico, and a portion of western Texas. The major load centers are located in the population centers of south central and southern Arizona and in north central New Mexico. The area has a high percentage of coal-fired steam capacity (over 52 percent), most of which is located near large coal reserves in the Four Corners area. The majority of hydroelectric resources are along the Colorado River. Hence, the area is characterized by long distances between load and generation sources. The area experiences an extremely high summer peak due to irrigation pumping and air conditioning loads.

The coordinating groups within the Arizona-New Mexico Power Area include the following:

1. New Mexico Power Pool (NMPP)
2. Arizona-Nevada Power Pool (AZNPP)
3. Arizona Public Service-Salt River Project Power Pool (APS-SRP)
4. Lower Colorado River Power Pool (LCRPP)
5 Arizona Power Pooling Association (AZPPA)
6. Salt River Project-Puget Agreement (SRPUA)
7. Western Energy Supply and Transmission Associates (WEST)
8. Agreement on Principles of Interconnected System Operations (PISO)
9. Arizona Public Service Company-Tucson Electric Power Company Power Pool (APS-TEP)
10. Arizona Public Service Company-Utah Power & Light Company Interconnection Agreement (APS-UP&L)
11. Arizona Public Service Company-Nevada Power Company Power Coordination Agreement (APS-NPC)
12. Southwest Area Transmission Planning Committee (SWAT)

The membership of these groups is listed in Table 11, Chapter 5. NMPP, AZNPP, LCRPP, AZPPA, and PISO are briefly discussed in this summary; a full discussion of all groups is provided in Chapter 5.

NEW MEXICO POWER POOL (NMPP)

NMPP consists of the major power suppliers in the western two-thirds of New Mexico and the El Paso area of Texas. The pool organization is based on an agreement signed in 1956, which provides for use by the pool members of transmission facilities owned by the then Bureau of Reclamation, now owned by WAPA, along the Rio Grande River. This agreement permitted the load centers near Albuquerque to be tied to those in the El Paso area. Through additional agreements, the pool members have expanded the coordination of planning and operations to include the services of emergency support, spinning reserve policy, and installed reserve principles. The pool maintains spinning reserve equal to the largest contingency, allocated to members on the basis of each member's peakloads. Under the original agreement, engineering, operating, and executive committees study the reliability and operating problems associated with the expansion of the joint transmission system necessary for the long distance transmission of power from generation sources to widely dispersed load centers.

ARIZONA-NEVADA POWER POOL (AZNPP)

AZNPP is composed of the Salt River Project, a publicly owned utility that serves the metropolitan Phoenix area; the Nevada Power Company; and the Western Area Power Administration. The basic pool agreement was signed in 1971 and is administered by an operating committee of two representatives of each party. The agreement provides for mutual emergency assistance and for exchange of spinning reserve capacity on an economy basis. The parties exchange economy energy under separate bilateral agreements.

LOWER COLORADO RIVER POWER POOL (LCRPP)

LCRPP is a formal contractual arrangement among Arizona Public Service Company, Southern California Edison Company (SCE), and the Imperial Irrigation District to serve their loads located in the area along the Colorado River in southwestern Arizona and southeastern California. For many years, this area was isolated from the main generation-transmission systems of two of the parties and is still relatively isolated. The agreement provides the basis for coordinated planning for loads and construction of jointly owned generating facilities in the load area, and for economy energy interchange and reciprocal emergency assistance. It establishes reserve capacity and spinning reserve responsibilities and sets forth policies encouraging joint construction of local power supply facilities.

THE ARIZONA POWER POOLING ASSOCIATION (AZPPA)

AZPPA is a voluntary, nonprofit corporation formed by two municipal utilities and a generation and transmission cooperative with service areas covering part of Arizona. The pool was organized to coordinate the operation of Federal hydroelectric capacity purchased by the members and the baseload thermal generation that members have installed to meet load growth in excess of Federal entitlements.

AGREEMENT ON PRINCIPLES OF INTERCONNECTED SYSTEMS OPERATION (PISO)

The participants in the large jointly owned electric generating plants in the Arizona-New Mexico area have developed an agreement on PISO to cover the coordinated operation of such plants and the associated widespread transmission network required to bring power from outlying plants to load centers. These principles closely resemble provisions usually found in comprehensive power pool agreements and express agreement on voluntarily maintained planning and operating standards in the following areas: installed reserve (15 percent of peakload), spinning reserve (interruptible load cannot exceed 15 percent of spinning reserve), and daily operation. Specific operating procedures and maintenance of units at the various plants are handled by engineering and operating committees for each plant. An advisory committee recommends regionwide maintenance schedules to the plant committees. Capacity and energy interchange transactions are arranged separately.

COORDINATION IN THE CALIFORNIA-NEVADA POWER AREA

CANVA is the general geographical area comprising the States of California and Nevada. In generating resources, the area is the second largest of the four power areas in the Western Region, with a 1980 winter capability of 40,103 MW. Reflecting the area's heavy reliance on scarce and expensive fuels, gas- and oil-fired generation accounts for 56 percent of the area's resources. Hydropower (conventional and pumped storage) plays an important role accounting for 26 percent of the resources. The area's major utilities in the north are the Pacific Gas and Electric Company (PG&E), Sacramento Municipal Utility District, the U.S. Water and Power Resources Service (WPRS),[3] WAPA, the Turlock-Modesto Irrigation Districts, the City and County of San Francisco, the California Department of Water Resources, and the Sierra Pacific Power Company (SPP). In the southern area, the major utilities

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[3]WAPA is the marketing agent for the WPRS (formerly the U.S. Bureau of Reclamation).

include the Southern California Edison Company (SCE); the San Diego Gas & Electric Company (SDGE); the Los Angeles Department of Water and Power (LDWP); the Cities of Glendale, Burbank, and Pasadena; WPRS; and the Nevada Power Company (NPC). Numerous other smaller systems either serve only retail loads with purchased power or sell the entire output of owned generation to another entity.

The California Power Pool Agreement (CPP) is the major pool in the area. Its present members are PG&E, SCE, and SDGE. Although LDWP is not a member, it does meet with CPP members for coordinated planning and maintenance studies.

THE CALIFORNIA POWER POOL

CPP is composed of the three major privately owned electric utilities in California; service territories of these systems cover essentially all of California with the exception of that part of northern California served by Pacific Power and Light Company and the service territories of the municipal utilities.

The agreement sets forth the contractual terms and conditions governing the interconnected operation of the area systems[4] of the three utilities. It provides for each of the pool member utilities to operate its system continuously and in parallel with each system of a nonpool member utility with which the pool utility shares an interconnection, and for the maintenance of interconnections in good operating condition.

The pool is administered by a board of control. Each member has one representative on the board. Board actions are advisory and members are not obligated to follow its recommendations, which require unanimous consent of each member of the board. The board is advised by an engineering and operating committee consisting of the chief planner and the power supply operating manager of each member. The pool agreement specifies that the board will review the reliability conditions of the pool periodically and establish installed and operating capacity obligations for the members sufficient to ensure minimum reliability conditions for the pool.

The current requirement for each member for installed generating capacity is an amount of capacity equal to the greater of (1) its load plus 10 percent, or (2) its load plus 5 percent plus the amount of capacity on scheduled maintenance. In any month, if a member cannot meet its installed capacity obligation, a charge of $2 per kW-month is made during each month of deficiency, and for 12 months after the last month of deficiency. Members may purchase power from other members and from nonmembers to meet deficiency requirements. The pool agreement contains a short-term (45 days) capacity rate ($2 per kW-month, 115 percent of incremental cost), which may be used

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[4]Area system is defined in Chapter 6, under the section titled "California Power Pool Description."

for this purpose, in which case the capacity is credited to the purchaser, and deducted from the capacity of the seller.

Each party is also required to maintain a spinning reserve at least equal to 7 percent of its expected daily peak demand. A party does not incur a spinning reserve deficiency, however, unless its spinning reserve drops below 5 percent. If a deficiency is incurred for two successive half-hourly determinations, the payment is $0.10 per kW-day. Such payment may be excused for a specified period based on several provisions enumerated in the agreement, of which the most commonly relate to an emergency on the system of a party.

Short-term power arrangements are provided under the pool agreement. These include: short-term firm service, emergency service, economy capacity service, economy energy service, capacity resources standby service, and energy interchange service. Long-term power transactions also are covered by separate agreements. Chapter 6 provides a more complete description of the services available under the CPP Agreement.

THE PACIFIC NORTHWEST-SOUTHWEST INTERTIE (PNW-SW)

The PNW-SW Intertie provides a means for interarea capacity and energy exchanges and is an important element of coordination in the Western Region. Operation of the two 500-kV a-c lines in the PNW-SW Intertie was initiated in 1968 and extended to southern California and the Arizona areas in 1969. The ±400-kV d-c line from Celilo, Oregon to Sylmar, near Los Angeles, was placed in service during 1970.

Both the a-c and d-c portions of the intertie are partly owned by members of NWPA and by members of CANVA. The transfer point between the two groups is at the California-Oregon border. All segments of each line comprising the intertie are separately owned except for the Nevada-California portion of the d-c tie, which is owned jointly by LDWP and SCE. Various agreements provide for access to the intertie by the owners of the line segments as well as by a number of nonowners. Transactions on the intertie between the NWPA and CANVA include the following:

1. Firm capacity and/or energy sales.
2. Federal surplus energy sales.
3. Non-Federal exportable energy delivered to BPA under exchange agreements by Pacific Northwest entities for sale to Southwest entities as surplus energy.
4. Non-Federal exportable energy sold by Pacific Northwest entities to Southwest entities under bilateral contracts and delivered to BPA for transmission over the intertie under terms of Contract No. 14-03-73155 (commonly called the Exportable Energy Agreement).
5. Federal surplus capacity exchanged for energy.

6. Non-Federal capacity exchanged for energy (Pacific Northwest to Southwest and Southwest to Pacific Northwest).
7. Energy storage transactions.
8. Direct delivery over the intertie of exportable energy by Pacific Northwest entities to Southwest entities.
9. Excess energy from Southwest entities to Pacific Northwest entities.
10. Seasonal capacity exchanges.

CHAPTER 1
INTRODUCTION

This report of the Western Region Task Force reviews the status of power pooling among utility systems operating in the 14 Western States, an area that encompasses almost 1,180,000 square miles. In addition to describing the current state of pooling, the report discusses benefits, identifies issues and problems that are impediments to increased pooling, and assesses the prospects and possibilities to conserve energy and to optimize efficient use of facilities and scarce resources through power pooling arrangements.

The report was drafted by the Federal Energy Regulatory Commission's (FERC) San Francisco regional office staff. Information developed in task force meetings, working papers prepared by the task force members, and other appropriate information from FERC's files were used in drafting the report. The drafts were reviewed by the task force to ensure that the report properly reflected their knowledge of the regional situation. The information and views expressed in the report are those of the task force and not necessarily those of the Federal Energy Regulatory Commission.

THE WESTERN REGION--A GENERAL DESCRIPTION

The Western Region (Figure 1) encompasses an area coincident with that portion of the Western Systems Coordinating Council (WSCC) that is situated in the continental United States. The Western Region includes all or part of Washington, Oregon, Idaho, Montana, Wyoming, Utah, Colorado, South Dakota, Nebraska, Arizona, New Mexico, Texas, California, and Nevada; but excludes that portion of the WSCC in the Canadian Provinces of British Columbia and Alberta.

Essentially all of the bulk power resources of the Western Region are provided by 19 investor-owned utilities, 18 municipal utilities, 13 public power systems, 4 Federal agencies, and 3 cooperatives. The principal generating resources include hydroelectric plants and gas-, oil-, and coal-fired steamplants. A few nuclear generating units are in operation, and more are under construction or planned to meet projected load requirements.

For purposes of study, the Western Region has been divided into four distinct subregions: the Northwest Power Area, the Rocky Mountain Power Area, the Arizona-New Mexico Power Area, and the California-Nevada Power Area.

FIGURE 1--The Western Region and its Subregions

DEFINITION OF POWER POOLING

The coordination and pooling of resources among utility systems in the region includes a variety of arrangements. Therefore, the task force adopted the following definition of power pooling to recognize the various activities in the Western Region that contribute to coordinated system operation and planning.

The Western Region Task Force has defined a power pool to be the physical interconnection and the coordinated planning and operation of the generation and transmission systems of two or more utility systems, with the objectives of reducing the cost of electric power to the consumer and achieving an adequate level of reliability. The definition includes both informal arrangements between utilities and bilateral agreements that provide for coordinated planning and operations.

POWER POOLING IN THE WESTERN REGION

The scope of coordination and pooling arrangements in the Western Region ranges from groups with formal organizational structures, permanent staffs, and well-defined functions, to informal arrangements between two or more utilities dealing with a specific aspect of system operations. In some instances these arrangements include most of the activities associated with the operation of interconnected systems and with the planning and construction of additional generation and transmission facilities. The task force identified the major coordinating groups and several others that carry out pooling functions in the Western Region. These groups are identified in Chapter 2.

Interconnections between power systems in the Western Region developed on a system-by-system, line-by-line basis. Although interconnection of all major utility systems is now an accomplished fact, the basic bilateral agreements to solve operational problems and to take advantage of economic opportunities still exist and are effective.

In many cases, systems are members of more than one coordinating arrangement. For example, some of the members of a power pool that coordinates system operations are also members of a second group that coordinates system planning. These same systems may also be members of other groups and parties to diverse bilateral arrangements. Arrangements are structured to best fit the needs of systems in the area. In the Western Region this complexity of arrangements is best demonstrated in the Northwest Power Area. (See Chapter 3.)

During the years of interconnected operations, the systems have developed channels of communication and continuous close contact. Task force members consider that the bilateral and multiparty arrangements--for jointly owned generation, economy interchange, reserve coordination, and coordination of planned outages--grow on a

continual basis, neighbor-to-neighbor, and form the "building blocks" for areawide and interarea coordination and pooling.

Pooling practices in the Western Region have been shaped in large part by the regional characteristics. Vast geographical expanses and concentration of indigenous fuel resources in States with low population densities--characteristics that are unique to the Western Region--have engendered coordinating arrangements to accommodate the special circumstances.

APPROACH TO THE STUDY

The Western Region Task Force meetings to establish facts and clarify issues on pooling and coordination in the region were held in San Francisco. The task force operated as an informal discussion group; viewpoints, opinions, and differences were expressed and recorded, but no attempt was made to resolve divergent views. Meetings were open to the public, but observers entered into discussions only at the invitation of the task force chairman. Members provided papers on various topics and documents and other material to describe the regional situation. Summary minutes of each meeting were prepared by the FERC staff and also used in the preparation of this report.

REPORT ORGANIZATION

Chapter 2 describes the extent of electric coordination within the Western Region and how coordination developed. Information is provided to identify all utilities, their resources, and their interconnections. Existing bilateral and multilateral agreements and jointly owned projects are listed.

Chapters 3, 4, 5, and 6, respectively, describe the significant coordinating organizations in the Northwest Power Area, the Rocky Mountain Power Area, the Arizona-New Mexico Power Area, and the California-Nevada Power Area. The benefits currently realized through these organizations and the outlook for further coordination within each subregion are discussed.

Chapter 7 discusses regulation as a factor in regional electric coordination. The role of State regulatory authorities in matters dealing with rates, economics, powerplant siting, and service of electric utilities is presented on a State-by-State basis.

Chapter 8 summarizes the more important real and perceived impediments to increased regional coordination that were identified by the task force and suggests ways by which these impediments might be eliminated or reduced.

Chapter 9 supplements the discussions in Chapters 3, 4, 5, and 6 on opportunities for increased coordination by looking at additional opportunities that cut across subregion boundaries.

Appendix A is a compilation of electric power data for the Western Region to supplement discussions in Chapter 2.

Appendix B contains letters of comment from organizations and agencies that were invited to review this report in draft form.

Appendix C presents the views of two task force members with respect to a specific power pooling issue in the California-Nevada Power Area. Appendix C also contains responses by individual task force members to comments of invited reviewers of this report.

CHAPTER 2
ELECTRIC COORDINATION IN THE WESTERN REGION

AREA DESCRIPTION AND GENERATION CHARACTERISTICS

The Western Region consists of the States of Washington, Oregon, California, Arizona, Nevada, Utah, Idaho, Wyoming, and Colorado in their entirety; the major portions of Montana and New Mexico; and small portions of South Dakota, Nebraska, and Texas as shown in Figure 1. To the north, the Western Region abuts the Canadian Provinces of British Columbia and Alberta, which have member systems in the Western Systems Coordination Council (WSCC). To the east, the Western Region abuts the Mid-Continent Area Reliability Coordination Agreement area (a part of FERC's North Central Region) and the Southwest Power Pool and Electric Reliability Council of Texas areas (both comprising FERC's South Central Region). The Western Region abuts Mexico to the south. The area encompassed by the Western Region is about one-third of the land area of the contiguous United States and represents about one-sixth of the total electrical load.

The region is traversed from north to south by two major mountain chains. One key characteristic of the region is that there are extremes--there are extremes in climate, precipitation, population density, electric load densities, and in distances between load centers and power generating sources.

Influenced partly by these extremes, four subregions have evolved. The subregions are the following:

1. The Northwest Power Area, consisting of Washington, Oregon, Idaho, and Utah, and parts of Montana, Wyoming, Nevada, and California
2. The Rocky Mountain Power Area, consisting of Colorado, and parts of Wyoming, South Dakota, and Nebraska
3. The Arizona-New Mexico Power Area, consisting of Arizona, and parts of New Mexico and Texas
4. The California-Nevada Power Area consisting of most of the land areas of California and Nevada

As of January 1, 1980, the region's total generating capability amounted to 101,196 MW. The Northwest Power Area is unique in that approximately three-fourths of its generating capability is represented by installed hydroelectric capacity; for the region as a whole, hydroelectric power provides over 41 percent of the entire

generating capability. The fuel mix in each subregion has distinctive but changing characteristics, with the proportion of hydroelectric power shrinking as time goes on. Table 1 gives a breakdown of this capacity by type and by subregion. Peakloads occur in the summer months through most of the Western Region, though the Pacific Northwest reports that system peaks occur in winter. However, the differences between summer and winter peaks in the region have been narrowing in recent years.

Appendix A provides a detailed tabular description of the electric power characteristics of the Western Region as of 1978. All electric utility systems are listed and located by subregions and States. Data for each utility include, where appropriate, installed generating capacity, system peakload, both major and radial interconnections, and sources from which each utility purchases bulk power. Appendix A was compiled by the FERC staff from FPC Forms 1 and 12, utility transmission line maps, and other data on file with FERC.

TRANSMISSION NETWORK

The first interconnections were made in the more populated, less isolated coastal areas of the Western Region as early as the 1920's. During intervening years, with technological advances and the construction of large hydroelectric resources and coal-fired resources at locations remote from load centers, more transmission lines were built and more systems were interconnected. As shown in Appendix A, virtually every utility system with generating resources in the Western Region is now interconnected with at least one other system. A qualitative appreciation of the growth of the regional transmission network in the years between 1949 and 1977 can be seen by comparing Figures 2 and 3. Figures 2 and 3 are simplified depictions of the Federal Power Commission Principal Electric Facility Maps of the region for the years 1949 and 1977, respectively.

Today the Western Region is served by an interconnected bulk power supply system consisting of more than 73,000 circuit miles of transmission. Table 2 is a tabulation of the circuit miles of transmission, by voltage level, in each power area of the Western Region.

The interconnected systems in the Western Region comprise a large loop referred to as the "Western Loop." The western side of this loop is the Pacific Northwest-Southwest Intertie, which consists of two 500-kV a-c circuits between John Day Dam on the Columbia River and Vincent, California, near Los Angeles, and a $\pm$ 400-kV d-c line from Celilo, Oregon to Sylmar, California, also near Los Angeles. The south side of the loop consists of 500-kV a-c circuits across southern California, Nevada, and Arizona. The eastern and northern sides consist of multiple 345-kV and 230-kV transmission lines through Utah, Colorado, Wyoming, Idaho, and Montana, and into Washington and Oregon.

TABLE 1--Existing Generating Capability as of January 1, 1980
(Winter Capability in Megawatts)

Generation Type	Northwest Power Area[1]	Rocky Mountain Power Area	Arizona-New Mexico Power Area	California-Nevada Power Area	Western Region Total	Percent of Total
Hydroelectric-Conventional	30,797	2,060	643	8,534	42,034	41.5
Hydroelectric-pumped storage	100	162	137	1,697	2,096	2.1
Steam--coal	7,560	3,168	6,573	1,910	19,211	19.0
Steam--gas and oil	323	374	2,858	22,629	26,184	25.9
Nuclear	1,920	200	0	1,402	3,522	3.5
Combustion turbine	637	667	1,389	2,018	4,711	4.6
Combined cycle	534	0	834	1,170	2,538	2.5
Geothermal	0	0	0	663	663	0.6
Internal combustion	30	53	15	80	178	0.2
Other	59	0	0	0	59	0.1
Total	41,960	6,684	12,449	40,103	101,196	100.0
Percent of WSCC total	41.5	6.6	12.3	39.6	100.0	

[1]Exclusive of member systems in Canada.
SOURCE: WSCC reply to FPC Docket R-362, April 1, 1980.

FIGURE 2--Transmission Interconnection Network in 1949

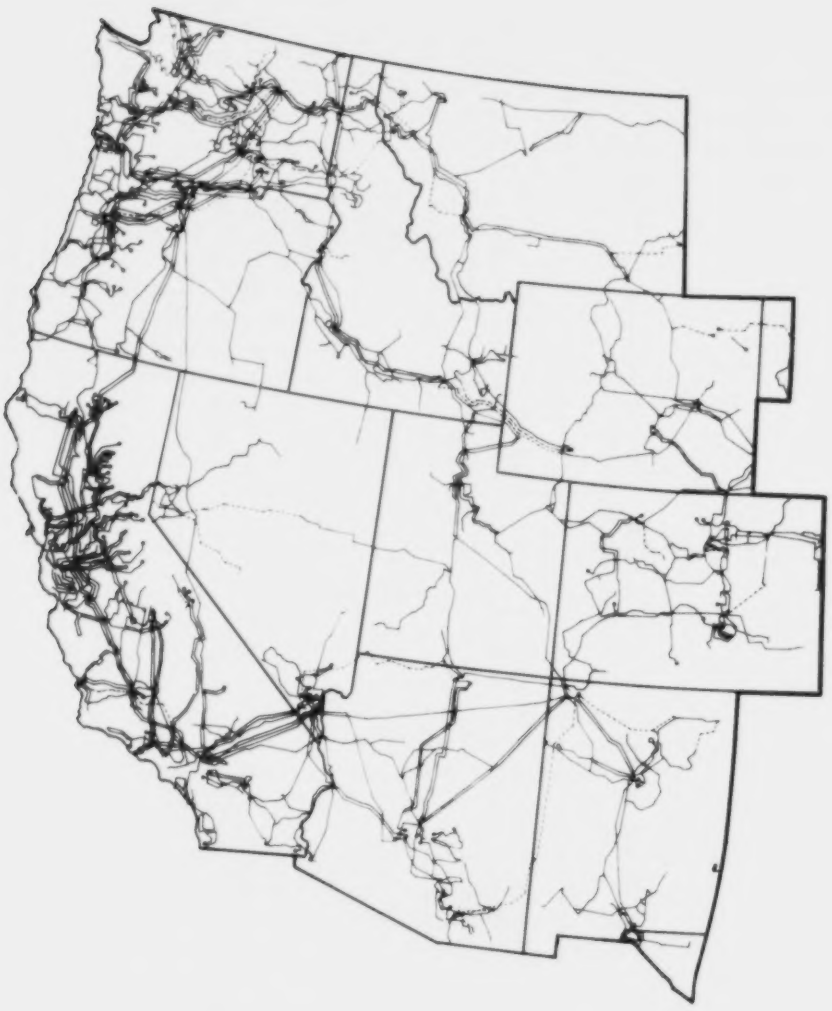

FIGURE 3--Transmission Interconnection Network in 1977

TABLE 2--Existing Transmission as of January 1, 1980
(Circuit Miles)

Voltage	Northwest Power Area[1]	Rocky Mountain Power Area	Arizona-New Mexico Power Area	California-Nevada Power Area	Western Region Total	Percent of Total
115-161 kV	13,372	5,154	3,930	9,050	31,506	42.7
230 kV	11,503	2,960	1,900	11,529	27,892	37.9
287-360 kV	2,510	181	2,859	373	5,923	8.0
500 kV	3,390	0	1,340	2,821	7,551	10.2
800 kV DC	264	0	0	580	844	1.2
Total	31,039	8,295	10,029	24,353	73,716	100.0
Percent of Total	42.1	11.3	13.6	33.0	100.0	

[1]Exclusive of circuit miles of member systems in Canada.

The interconnected bulk power system within the Western Region is continually being expanded to ensure efficient and economical use of resources, and adequacy and reliability of service. During 1979 alone, 769 additional circuit miles of transmission were added. The new transmission included 800 miles of 500 kV (replacing 102 miles of 287-360 kV), 23 miles of 230 kV, and 48 miles of 115-161 kV. Appendix A includes a discussion of bulk power transmission facilities under construction and those proposed for the next 10 years.

In the Western Region, the only Canada-United States interconnections are between British Columbia and Washington. British Columbia Hydro and Power Authority and Bonneville Power Administration (BPA) are connected by two 500-kV circuits at Blaine, Washington, and a 230-kV circuit at Boundary, Washington. Cominco Ltd. and BPA are connected by a 230-kV circuit at Boundary, Washington. Numerous interconnections exist between the United States and Mexico, but at present there is no synchronous interconnection between the Western Region and Mexico. Four 230-kV interconnections between southern California and Mexico are planned to be placed in operation between 1982 and 1986.[1]

No major transmission lines interconnect the Western Region with the adjoining South Central Region. The Western Region has only a limited interconnection with the North Central Region at the Stegall Substation in Nebraska, offering a bulk power transfer capability of 100 MW over an a-c/d-c tie. Appendix A describes the Stegall interconnection as well as several minor interconnections where power can be exchanged between the two regions by transferring the output of generating units.

PACIFIC NORTHWEST-SOUTHWEST INTERTIE

The existing intertie system is made up of three major north-south transmission lines, constructed during the 1960's. The three lines are commonly referred to jointly as the Pacific Northwest-Southwest Intertie Facilities. The current intertie facilities are shown on Figure 4. The major north-south components consist of a 1361-kilometer (846-mile) direct current transmission line from Celilo, Oregon to Sylmar, California, operating at a voltage of 800-kV dc (± 400 kV), and two 1666-kilometer (1035-mile) a-c lines extending from John Day, Oregon to Vincent, California, operating at a voltage of 500-kV ac. Several facilities associated with the intertie are one 230-kV a-c line from Round Mountain to Cottonwood in northern California; one 345-kV a-c line from Mead

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[1]A detailed analysis of United States/Mexico interconnections is contained in the recently completed study concerning electricity exchange between the United States and Mexico. (DOE/RG-033, Electricity Exchanges, United States/Mexico, May 1980.)

SOURCE: Principal Power Facilities Western U.S., WAPA, Map No. A-2, December 1979. (As modified).

FIGURE 4--Pacific Northwest-Southwest Intertie

substation, Nevada to Liberty substation, Arizona; one 230-kV a-c line from Liberty substation to Pinnacle Peak substation, both near Phoenix, Arizona; and three 500-kV a-c lines between Los Angeles, California and Mead, Nevada.

The two John Day-Vincent 500-kV a-c lines were constructed and placed into operation in 1968 and 1969, respectively, following the original proposal for interconnection of the Pacific Northwest and Southwest Regions. Ownerships and operational responsibilities of the a-c intertie are shown on Figure 4. These a-c lines are subject to unscheduled power flow or circulating flow and are a part of the WSCC bulk transmission system. The California utilities consider the rated capacity of the a-c intertie as 2500 MW, assuming no loop flow.

The d-c intertie was constructed and placed in operation in May 1970, also as a part of the original proposal to interconnect the Pacific Northwest and the Southwest. The $\pm$ 400 kV d-c intertie has been uprated on a test basis since the spring of 1979 from 1800 amperes (1440 MW) to 2000 amperes (1600 MW). The northern section of the d-c facilities consists of the Celilo converter terminal at The Dalles, Oregon, and 426 kilometers of d-c line in Oregon. The Oregon facilities are operated and owned by BPA. The southern section of the line, operated by the Los Angeles Department of Water & Power (LDWP) and jointly owned by LDWP, Southern California Edison (SCE), and the cities of Burbank, Glendale, and Pasadena, consists of the Sylmar converter terminal near Los Angeles and 935 kilometers of d-c line in Nevada and California.

Current intertie uses, which include capacity sales and firm- and nonfirm-energy sales, are the following:

1. Firm capacity and/or energy sales
2. Federal surplus energy sales
3. Non-Federal exportable energy delivered to BPA under exchange agreements by Pacific Northwest entities for sale to Southwest entities as surplus energy
4. Non-Federal exportable energy sold by Pacific Northwest entities to Southwest entities under bilateral contracts and delivered to BPA for transmission over the intertie under terms of Contract No. 14-03-73155 (commonly called the Exportable Energy Agreement)
5. Federal surplus capacity sales or exchange for energy
6. Non-Federal capacity sales or exchange for energy (Pacific Northwest to Southwest and Southwest to Pacific Northwest)
7. Energy storage transactions
8. Direct delivery over the intertie of exportable energy by Pacific Northwest entities to Southwest entities
9. Excess energy from Southwest entities to Pacific Northwest entities
10. Seasonal capacity exchanges

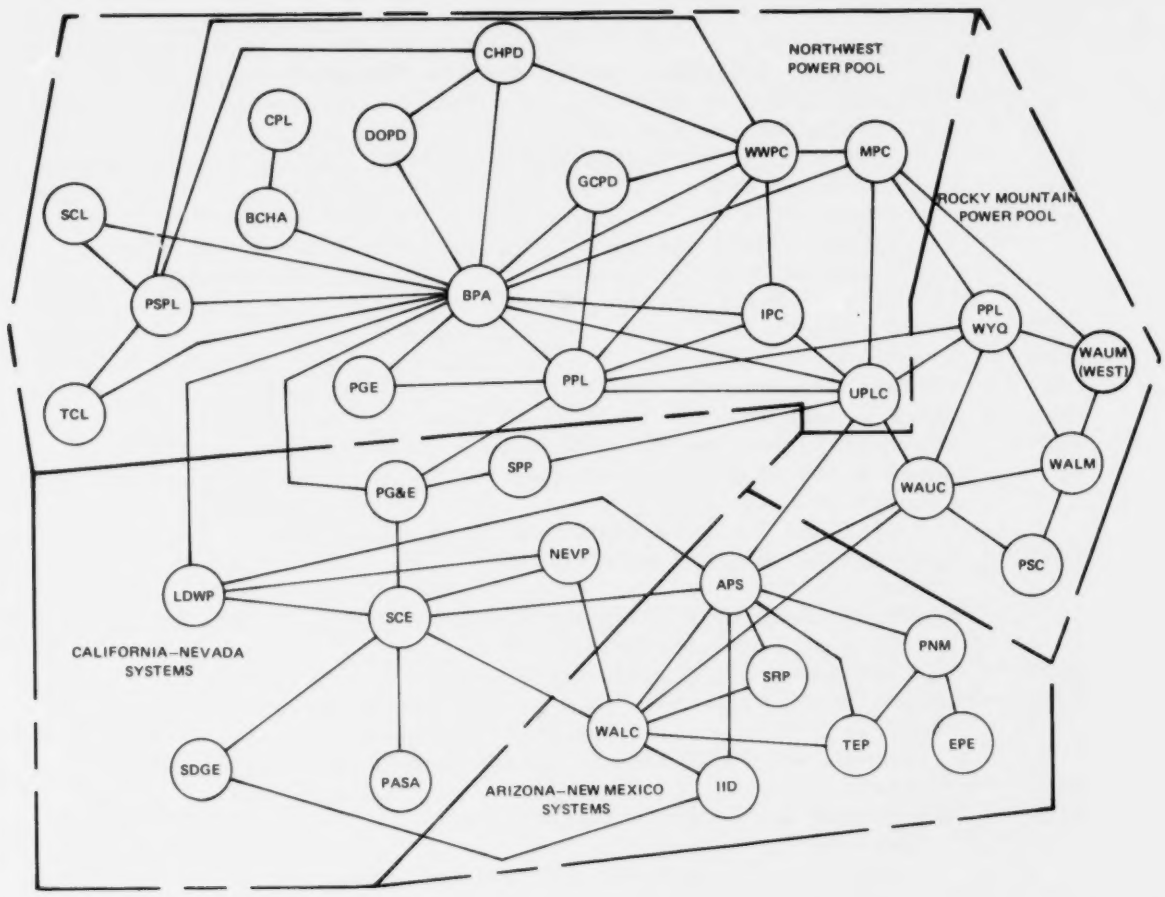
CONTROL AREAS

The utility systems of the Western Region have established 34 control areas. Fifteen control areas are in the Northwest Power Area, five are in the Rocky Mountain Power Area, seven are in the Arizona-New Mexico Power Area, and seven are in the California-Nevada Power Area.

Interconnected utilities manage the supply of electricity within their service area through the control area concept. A control area may be for a single system or, by arrangements between utilities, may encompass more than one system. Within a control area, the generation is managed so that changes in load requirements are met by the area's own generation resources while maintaining the prearranged levels of power interchanges with adjoining control areas. This coordination is accomplished by a system of controls that changes area generation levels to maintain frequency and restore the net flows to the scheduled levels when the net flows over the interarea tielines go off schedule. If the area control center is equipped with a control system that achieves economic selection of generation at the same time that it fulfills the task of tieline regulation, maximum operating economy of available equipment is realized. Although this optimization is often achieved when the control area coincides with an individual utility system, it is not always achieved when the control area covers more than one system. The operating coordination achieved through the application of the control area concept to multiple systems within a single control area can range from that achieved by a formal power pool to that obtained by simple bilateral interconnection agreements between two systems.

Figure 5 illustrates the region's load control areas and associated interconnections. Although only one interconnection between any two control areas is shown on the figure, the interconnection may actually consist of several ties at various voltage levels. Also for clarity, the figure does not show numerous contractual interconnections for power scheduling. A tabulation of the Western Region load control areas and power systems within the control areas follows.

To facilitate power scheduling, coordination of joint operations, and exchange of information important to interconnected system reliability and economy, an extensive communication system has evolved between system dispatching offices of the interconnected systems. Communication channels are provided by various means, such as privately owned microwave systems, power line carrier circuits, radio, and channels leased from common carrier telephone companies. WSCC has established a voice-facsimile communication system.



SOURCE: WSCC "Bulk Power Supply Program " 1979-89,
April 1, 1980

FIGURE 5--Western Region Control Areas

CONTROL AREAS AND POWER SYSTEM INTERCONNECTIONS

APS - Arizona Public Service Co.
BCHA - British Columbia Hydro & Power Authority
  Controls for:
    Aluminum Smelters & Chemical Co. Ltd.
    West Kootenay Power & Light Co.
BPA - Bonneville Power Administration
  Controls for:
    Corps of Engineers (North Pacific Division)
    Cowlitz County PUD
    Eugene Water & Electric Board
    USWP Pacific Northwest Region
CPL - Calgary Power Ltd.
  Controls for:
    Alberta Power Limited
    Edmonton Power
    City of Medicine Hat, Alberta
CHPD - Chelan County PUD
DOPD - Douglas County PUD
EPE - El Paso Electric Co.
GCPD - Grant County PUD
IID - Imperial Irrigation District
IPC - Idaho Power Company
  Controls for:
    BPA/USWP Southern Idaho load area
LDWP - Los Angeles Dept. of Water & Power
  Controls for:
    City of Burbank, California
    City of Glendale, California
MPC - Montana Power Company, The
NEVP - Nevada Power Company
  Controls for:
    Division of Colorado River Resources, State of Nevada
PASA - Pasadena, City of, California
PG&E - Pacific Gas & Electric Co.
  Controls for:
    Department of Water Resources/California
    Modesto Irrigation District
    Sacramento Municipal Utility District
    City and County of San Francisco, California
    Turlock Irrigation District
    WAPA Mid-Pacific Region
PGE - Portland General Electric Co.
PNM - Public Service Company of New Mexico
  Controls for:
    Community Public Service Company
    Plains Electric Generation and Transmission
      Cooperative, Inc.
    WAUC load at Los Alamos, New Mexico

PPL - Pacific Power & Light Co.
PPL-WYO Pacific Power & Light Co., Wyoming Division
PSC - Public Service Company of Colorado
Controls for:
City of Colorado Springs, Colorado
Southern Colorado Power Co.
City of Lamar, Colorado
PSPL - Puget Sound Power & Light Co.
SCE - Southern California Edison Co.
Controls for:
Metropolitan Water District of Southern California
SCL - Seattle City Light
SDGE - San Diego Gas & Electric Co.
SPP - Sierra Pacific Power Co.
Controls for:
Mt. Wheeler Power, Inc.
SRP - Salt River Project
TCL - Tacoma City Light
TEP - Tucson Electric Power Co.
UPLC - Utah Power & Light Co.
Controls for:
BPA/USWP Palisades load area
WAUC Preference Customer
WALC - Western Area Power Administration, Lower Colorado Region
Controls for:
Arizona Power Authority
Arizona Electric Power Cooperative, Inc.
USWP-Lower Colorado Region
WALM - Western Area Power Administration, Lower Missouri Region
Controls for:
Black Hills Power & Light Co.
Cheyenne Light, Fuel & Power Co.
Platte River Power Authority
Tri-State Generation & Transmission Association
USWP-Lower Missouri Region
WAUC - Western Area Power Administration, Upper Colorado Region
Controls for:
Colorado-Ute Electric Association, Inc.
City of Farmington, New Mexico
Moon Lake Electric Association
USWP-Upper Colorado Region
WAUM - Western Area Power Administration, Upper Missouri Region
Controls for:
USWP-Upper Missouri Region
WWPC - Washington Water Power Co.

WESTERN SYSTEMS COORDINATING COUNCIL

The Western Systems Coordinating Council, referred to as WSCC, is one of the nine regional reliability councils. It was formed in March 1967, and the execution of the WSCC Agreement was completed on August 4, 1967, with 40 signatories. Those "charter members" represented electric power systems engaged in bulk power generation and/or transmission serving all or part of 14 Western States and British Columbia, Canada. An amendment to the WSCC Agreement provides for the admission of operating power systems not eligible for membership under the bulk power system criteria as nonvoting affiliate members.

The formation of WSCC preceded the formation of the National Electric Reliability Council (NERC) by nearly one year. WSCC and the other eight regional reliability councils were formed because of national concern regarding the reliability of the interconnected bulk power systems and the ability to operate these systems without widespread failures in electric service. This national concern resulted from the massive breakup of the Northeast interconnected system in 1965 and the publicity given to it and other subsequent interconnected system disturbances in this country, including those in the West.

WSCC member systems have long recognized the many benefits of interconnected system operation. During the mid-1960's, expansion of interconnections among systems in the Western States and Western Canada resulted in the complete interconnection of the entire region. Interconnections to the eastern systems followed in 1967. As this expansion of interconnections between systems in the Western States was taking place, the coordination among these systems at the operating level was being implemented through the formation of informal operating organizations that grew in stature with the extension of interconnections. The "Operating Guides" of the North American Power Systems Interconnection Committee (NAPSIC) were generally adopted for the guidance of operations (NAPSIC is now the NERC Operating Committee).

WSCC now consists of 47 member systems and 14 affiliate members with the recent admissions of Calgary Power Ltd. as a member system and Northern California Power Agency as an affiliate member. The bulk power electric utility systems (member systems) include 19 investor-owned utilities, 9 municipal utilities, 12 public power systems, 4 Federal agencies, and 3 Canadian systems. The affiliate members represent 9 municipal utilities, 4 cooperatives, and 1 public utility district. These utility systems provide substantially all of the electric service in Washington, Oregon, California, Arizona, New Mexico, Nevada, Utah, Idaho, Montana, Wyoming, and Colorado; as well as portions of South Dakota, Nebraska, Texas, and the Canadian Provinces of British Columbia and Alberta. The WSCC member systems and affiliate members are listed below and the common abbreviations used throughout this report for utilities in the Western Region are also included.

WSCC extends over nearly 1.8 million square miles, representing a service area equivalent to more than one-half of the contiguous land area of the United States. WSCC is the largest, geographically, of the nine regional councils of the National Electric Reliability Council (NERC), and its members provide electric service to approximately 44 million people.

MEMBER SYSTEMS (47)

AEPC - - - Arizona Electric Power Cooperative, Inc.
APA - - - Arizona Power Authority
APS - - - Arizona Public Service Company
BHPL - - - Black Hills Power & Light Company
BPA - - - Bonneville Power Administration
BCHA - - - British Columbia Hydro & Power Authority
CPL - - - Calgary Power Ltd.
CCS - - - Colorado Springs, City of
CUEA - - - Colorado-Ute Electric Association, Inc.
USCE - - - Corps of Engineers (North Pacific Division)
CDWR - - - Department of Water Resources/California
EPE - - - El Paso Electric Company
EWEB - - - Eugene Water & Electric Board
GLEN - - - Glendale Public Service Department
IPC - - - Idaho Power Company
LDWP - - - Los Angeles Department of Water and Power
MWD - - - Metropolitan Water District/Southern California
MPC - - - Montana Power Company, The
NEVP - - - Nevada Power Company
PG&E - - - Pacific Gas and Electric Company
PPL - - - Pacific Power & Light Company
PASA - - - Pasadena, City of
PEGT - - - Plains Electric Generation and Transmission Cooperative, Inc.
PRPA - - - Platte River Power Authority
PGE - - - Portland General Electric Company
PSC - - - Public Service Company of Colorado
PNM - - - Public Service Company of New Mexico
CHPD - - - PUD No. 1 of Chelan County
COPD - - - PUD No. 1 of Cowlitz County
DOPD - - - PUD No. 1 of Douglas County
GCPD - - - PUD of Grant County
PSPL - - - Puget Sound Power & Light Company
SMUD - - - Sacramento Municipal Utility District
SRP - - - Salt River Project
SDGE - - - San Diego Gas & Electric Company
SCL - - - Seattle Department of Lighting (Seattle City Light)
SPP - - - Sierra Pacific Power Company
SCE - - - Southern California Edison Company
SCPC - - - So. Colorado Power Division, Central Tele. & Util. Corp.

TCL - - - Tacoma Department of Public Utilities (Tacoma City Light)
TSGT - - - Tri-State G&T Association, Inc.
TEP - - - Tucson Electric Power Company
UPLC - - - Utah Power & Light Company
WWPC - - - Washington Water Power Company, The
USWP - - - Water and Power Resources Service
USFC - (Denver Federal Center)
USLC - (Lower Colorado)
USLM - (Lower Missouri)
USMP - (Mid-Pacific)
USPN - (Pacific Northwest)
USSW - (Southwest)
USUC - (Upper Colorado)
USUM - (Upper Missouri)
WKPL - - - West Kootenay Power & Light Company
WAPA - - - Western Area Power Administration
WAHQ - (Golden, Colorado)
WALC - (Boulder City, Nevada)
WALM - (Denver, Colorado)
WAMP - (Sacramento, California)
WAUC - (Salt Lake City, Utah)
WAUM - (Billings, Montana)

AFFILIATE MEMBERS (14)

Anaheim, City of
Bountiful City Light and Power
Electrical District No. 2, Coolidge, Arizona
Garkane Power Association, Inc.
Lamar Utilities Board (City of Lamar)
Lodi, City of
Navajo Tribal Utility Authority
Northern California Power Agency
Palo Alto, City of
PUD of Clark County, Vancouver, Washington
Redding, City of
Riverside, City of
St. George, City of
Santa Clara, City of

FEDERAL SYSTEMS

Electric power generated at Federal multipurpose water projects in the Western Region is a significant contribution to the total regional generating capability. The Bonneville Power Administration (BPA) is responsible for the marketing of all Federal power and the transmission of all Federal and certain non-Federal power in the Northwest Power Area. The central role played by BPA and the

Federal projects in the Northwest is discussed in Chapter 3. The Western Area Power Administration (WAPA) transmits and markets Federal power in each of the other three subregions.

The power that WAPA transmits and markets is generated at hydroelectric generating plants in its service area. These plants are operated by the U.S. Army Corps of Engineers and the Water and Power Resources Service (formerly the Bureau of Reclamation). Additionally, WAPA markets the United States entitlement from the Navajo coal-fired plant near Page, Arizona. WAPA's customers consist of cooperatives, municipalities, public utility districts, private utilities, Federal and State agencies, and irrigation districts. These utilities provide retail service in all or part of California, Nevada, Montana, Arizona, Utah, New Mexico, Texas, Colorado, Wyoming, South Dakota, Nebraska, and in four States outside of the Western Region. As a measure of the role federally generated power has in the Rocky Mountain, Arizona-New Mexico, and California-Nevada Power Areas, WAPA contributed about 13 percent of the total 1978 summer peak-hour demand requirement.

COORDINATING GROUPS AND POOLING ARRANGEMENTS

In addition to the Western Systems Coordinating Council, which has been previously described, 23 coordinating groups and pooling arrangements exist in the Western Region. These groups are varied in purpose, function, and membership and include those based on bilateral and multiparty agreements as well as those that do not involve contractual arrangements. Table 3 lists, by subregions, the 23 coordinating groups addressed by the task force. Included in that listing for each group are (1) the nature of the organization (i.e., formal or informal); (2) the purposes, functions, and activities; and (3) the number of participants. Table 4 identifies the utility membership for 13 selected coordinating organizations.

Tables 3 and 4 demonstrate the following:

- The multiplicity of coordinating groups in the region
- The overlapping membership of the coordinating groups
- The "building blocks" for coordination in the region

Detailed descriptions of the coordinating groups and power pooling arrangements within each subregion are provided in Chapters 3, 4, 5, and 6.

JOINTLY OWNED GENERATING UNITS

Table 5 is a list of powerplants in the Western Region with jointly owned generating units. In the 36 plants listed, there are 14 jointly owned generating units (41,257 MW) involving a total of 46 utilities. Table 5 provides details on these units including type, size, ownership, operator, and inservice date.

TABLE 3--Coordinating Groups and Pooling Arrangements in the Western Region

			Pool Functions								
	Formal	Informal	Planning	Operating	Promotes Joint Facility Ownership	System Reliability	Resources Development	Emergency Assistance	Coord. Maint. Schedule Reservoir Storage	Number of Participants Member/Affiliates	
NWPA											
Intercompany Power Pool		X	X	X	X	X				7	
Mid-Columbia River Hourly Coordination Agreement	X			X				X	X	6	
Northwest Power Pool		X		X		X			X	20	
Pacific Northwest Coordination Agreement	X			X						16	1
Pacific Northwest Utilities Conference Committee		X	X		X	X	X	X		25	2
Public Generating Power Pool		X	X	X	X					7	
Public Power Council		X	X		X		X			113	
RMPA											
Colorado Power Pool	X			X		X		X	X	4	
Inland Power Pool	X			X		X		X	X	13	
Rocky Mountain Power Pool		X		X		X		X	X	22	
AZNMA											
Agreement on Principles of Interconnected System Operations[1]	X		X	X	X	X		X	X	10	
Arizona-Nevada Power Pool	X			X		X		X	X	3	
Arizona Power Pooling Association		X	X	X		X		X	X	3	
Arizona Public Service-Nevada Power Coordination Agreement	X		X					X		2	
Arizona Public Service-Salt River Project Power Pool	X		X	X	X	X		X	X	2	
Arizona Public Service-Tucson Electric Power Coordination Agreement	X			X	X	X		X		2	
Arizona Public Service-Utah Power & Light Interconnection Agreement	X		X					X		2	
Lower Colorado River Power Pool	X			X	X	X		X		3	
New Mexico Power Pool		X	X	X	X	X		X	X	5	
Salt River Project-Puget Sound Power & Light Exchange Agreement	X			X						3	
Southwest Area Transmission Planning Committee Agreement	X		X							8	
Western Energy Supply & Transmission Associates	X		X			X				20	
CANVA											
California Power Pool	X		X	X		X		X	X	3	

[1]Agreement on Principles of Interconnected System Operations for jointly owned projects in AZ, NM, NV (Four Corners Units 4 & 5, Mohave, Navajo, Palo Verde & Transmission Lines).

TABLE 4--Coordinating Organizations Western Region
Membership Listing

Utility Name	Northwest Power Pool	Inter-Company Pool	Colorado Power Pool	Rocky Mountain Power Pool	New Mexico Power Pool	Arizona-Nevada Power Pool	Lower Colorado River Power Pool	Arizona Power Pooling Assn.	Inland Power Pool	Southwest Area Transm. Planning Committee Agreement	California Power Pool	Pacific N.W. Coordination Agreement	Pacific N.W. Utilities Conference Committee
Arizona Electric Power Cooperative, Inc.													
Arizona Public Service Company								X		X			
Basin Electric Cooperative							X		X[1]	X			
Black Hills Power and Light Company				X					X				
Bonneville Power Administration	X			X									
British Columbia Hydro and Power Authority	X											X	X[2]
Calgary Power Ltd.	X												
Central Lincoln Peoples' Utility District													X
Central Telephone & Utilities Corp., Southern Colorado Power Division			X	X									
Cheyenne Light, Fuel, and Power Company				X									
City of Forest Grove, OR													
City of McMinnville, OR													X
City of Milton-Freewater													X
Colockum Transmission Company													X
Colorado Springs Dept. of Public Utilities			X	X								X	
Colorado-Ute Electric Association, Inc.				X					X				
Community Public Service Company					X				X				
Electric District No. 2, Pinal County								X					
El Paso Electric Company					X				X[1]	X			
Eugene Water and Electric Board	X												
Idaho Power Company	X	X										X	X
Imperial Irrigation District							X						
Intermountain Consumer Power Association									X[1]				
Lamar Utilities Board			X	X									
Los Angeles Dept. of Water and Power										X[3]			
Mesa City Utilities								X					

TABLE 4--Coordinating Organizations Western Region
Membership Listing (Continued)

Utility Name	Northwest Power Pool	Inter-Company Pool	Colorado Power Pool	Rocky Mountain Power Pool	New Mexico Power Pool	Arizona-Nevada Power Pool	Lower Colorado River Power Pool	Arizona Power Pooling Assn.	Inland Power Pool	Southwest Area Transm. Planning Committee Agreement	California Power Pool	Pacific N.W. Coordination Agreement	Pacific N.W. Utilities Conference Committee
Nebraska Public Power District				X									
Nevada Power Company						X							
Pacific Gas and Electric Company[4]											X		
Pacific Power and Light Company	X	X										X	X
Pacific Power and Light Company-Wyoming Division				X									
Plains Electric G&T Cooperative, Inc.					X				X				
Platte River Power Authority				X					X				
Portland General Electric Company	X	X										X	X
Public Service Company of Colorado			X	X					X				
Public Service Company of New Mexico					X				X	X			
Public Utility District No. 1 of Chelan County	X											X	X
Public Utility District No. 1 of Clallam County													X
Public Utility District No. 1 of Clark County													X
Public Utility District of Cowlitz County												X	X
Public Utility District No. 1 of Douglas County	X											X	X
Public Utility District No. 1 of Ferry County													X
Public Utility District No. 1 of Franklin County													X
Public Utility District No. 2 of Grant County	X											X	X
Public Utility District No. 1 of Grays Harbor County													X
Public Utility District No. 1 Kittitas County													X
Public Utility District No. 1 of Klickitat County													X
Public Utility District of Pend Oreille County												X	
Public Utility District No. 1 of Snohomish County													X

TABLE 4--Coordinating Organizations Western Region
Membership Listing (Continued)

Utility Name	Northwest Power Pool	Inter-Company Pool	Colorado Power Pool	Rocky Mountain Power Pool	New Mexico Power Pool	Arizona-Nevada Power Pool	Lower Colorado River Power Pool	Arizona Power Pooling Assn.	Inland Power Pool	Southwest Area Transm. Planning Committee Agreement	California Power Pool	Pacific N.W. Coordination Agreement	Pacific N.W. Utilities Conference Committee
Puget Sound Power & Light Company	X	X											
Salt River Project				X		X			X	X		X	X
San Diego Gas and Electric Company											X		
Seattle Department of Lighting	X												
Southern California Edison Company[5]							X			X	X	X	X
Tacoma Public Utilities Lighting Division	X												
Tri-State Generation & Transmission Association, Inc.				X					X			X	X
The Montana Power Company	X	X		X									
The Washington Water Power Company	X	X										X	X
Tucson Electric Power Company				X					X	X		X	X
U.S. Water and Power Resources Service				X									
U.S. Army Corp of Engineers	X												
Utah Power and Light Company	X	X		X								X	X[2]
Washington Public Power Supply System	X												
Western Area Power Administration-Upper Colorado	X			X	X				X				X
Western Area Power Administration-Lower Missouri				X					X				
Western Area Power Administration-Lower Colorado						X				X			
West Kootenay Power & Light Company, Ltd.	X												
Wyoming Municipal Power Agency				X					X				
Total	20	7	4	22	5	3	3	3	16	8	3	16	25/2

[1]Has expressed interest in becoming a member of the Inland Power Pool, but has not yet been admitted.
[2]Represented, but not a member.
[3]Los Angeles Department of Water and Power is not currently a member of the California Power Pool. However, the Department is participating with the other members of the pool in studies to determine if there are benefits available that are not now being realized under present pooled operations.
[4]The Pacific Gas and Electric Area System includes the systems of the Central Valley Projects; City and County of San Francisco and the Sacramento Municipal Utility District; the generating plants of the East Bay Municipal District; Merced Irrigation District; Oroville-Wyandotte Irrigation District; Placer County Water Agency; Tri-Dam Project of Oakdale and San Joaquin Irrigation Districts; and the Yuba County Water Agency.
[5]The Southern California Edison Area System includes the system of the Metropolitan Water District.

TABLE 5--Western Region Jointly Owned Plants

Plants	Location State	Type[1]	Fuel[2]	Unit	Capacity of Unit (MW)	Ownership Company	Ownership Percent	Operator	Status[3] as of January 1980	Inservice Date (year)	Comments
Four Corners	NM	ST	C	4	800	APS	15.0				
						SCE	48.0	APS	E	1969	
						PNM	13.0				
				5	800	SRP	10.0	APS	E	1970	
						TEP	7.0				
						EPE	7.0				
Mohave	NV	ST	C	1	790	SCE	56.0	SCE	E	1971	
						LDWP	20.0				
				2	790	NEVP	14.0	SCE	E	1971	
						SRP	10.0				
Navajo	AZ	ST	C	1	750	SRP	21.7	SRP	E	1974	
						APS	14.0				
				2	750	TEP	7.5	SRP	E	1975	
						LDWP	21.2				
				3	750	NEVP	11.3	SRP	E	1976	
						USLC	24.3				
San Juan	NM	ST	C	2	306	PNM	50.0	PNM	E	1973	
				1	314			PNM	E	1976	
				3	480	TEP	50.0	PNM	E	1979	
Hayden	CO	ST	C	2	262	SRP	80.0	CUEA	E	1976	
						CUEA	20.0				
Craig	CO	ST	C	2	400	CUEA	29.0	CUEA	UC	1980	
					400	SRP	29.0	CUEA	UC	1980	
						TSGT	24.0				
						PRPA	18.0				
Yuma-Axis	AZ	ST	FO6	1	75	APS	33.3	APS	E	1959	
						SCE	33.3				
						IID	33.3				
Centralia	WA	ST	C	1	650	PPL	47.5	PPL	E	1971	
						WWPC	15.0				
				2	650	PSPL	7.0	PPL	E	1972	
						PGE	2.5				
						SCL	8.0				
						TCL	8.0				
						SHPD	8.0				
						GHPD	4.0				
Jim Bridger	WY	ST	C	1	500	PPL	66.7	PPL	E	1974	
				2	500	IPC	33.3	PPL	E	1975	
				3	500			PPL	E	1976	
				4	500			PPL	UC	1979	
Wyodak	WY	ST	C	1	332	PPL	80.0	PPL	E	1978	
						BHPL	20.0				
Hanford NPR	WA	NU	PL	1	420	DOE[4]	100.0	WPPSS/BPA	E	1966	(4)
				2	420	WPPSS[4]	100.0	WPPSS/BPA	E	1966	(4)
Packwood Lake	WA	HY	--	1	30	WPPSS[4]	100.0	WPPSS/BPA	E	1964	
WNP-2	WA	NU	UR	1	1100	WPPSS[4]	100.0	WPPSS/BPA	UC	1981	(4)
WNP-1	WA	NU	UR	1	1250	WPPSS[4]	100.0	WPPSS/BPA	UC	1983	(4)

TABLE 5--Western Region Jointly Owned Plants (Continued)

Plants	Location State	Type[1]	Fuel[2]	Unit	Capacity of Unit (MW)	Ownership Company	Ownership Percent	Operator	Status[3] as of January 1980	In-service Date (year)	Comments
WNP-3	WA	NU	UR	1	1240	WPPSS[4]	70.0	WPPSS/BPA	UC	1984	(4)
						PPL	10.0				
						PGE	10.0				
						PSPL	5.0				
						WWPC	5.0				
WNP-4	WA	NU	UR	1	1250	WPPSS[4]	100.0	WPPSS/BPA	UC	1985	(4)
WNP-5	WA	NU	UR	1	1240	WPPSS[4]	90.0	WPPSS/BPA	UC	1986	(4)
						PPL	10.0				
San Luis	CA	PS	--	1	53				E	1968	
				2	53				E	1968	
				3	53				E	1968	
				4	53	CDWR	52.0	USMP	E	1968	
				5	53	USMP	48.0		E	1968	
				6	53				E	1968	
				7	53				E	1968	
				8	53				E	1968	
Colstrip	MT	ST	C	1	350	MPC	50.0	MPC	E	1975	
				2	350	PSPL	50.0	MPC	E	1976	
				3	700	MPC	27.9	MPC	UC	1984	
						PSPL	23.2			1984	
				4	700	PGE	18.6		UC		
						WWPC	14.0				
						PPL	9.3				
						BEPC	7.0				
Trojan	OR	NU	UR	1	1080	PGE	67.5	PGE	E	1976	
						EWEP	30.0				
						PPL	2.5				
San Onofre	CA	NU	UR	1	436	SCE	80.0	SCE	E	1968	
						SDGE	20.0				
				2	1100			SCE	UC	1981	
				3	1100			SCE	UC	1982	
Palo Verde	AZ	NU	UR	1	1270	APS	29.1	APS	UC	1983	
						SRP	23.4				
				2	1270	EPE	15.8	APS	UC	1984	
						PNM	10.2				
				3	1270	SCE	15.8	APS	UC	1986	
						LDWP	5.7				
Boardman	OR	ST	C	1	530	PGE	80.0	PGE	UC	1980	
						IPC	10.0				
						PNWG (Pacific Northwest Generating Co.)	10.0				
Coronado	AZ	ST	C	1	350	SRP	70.0	SRP	E	1979	LDWP will participate until Palo Verde is in service 5-1983
						LDWP	30.0				
				2	350			SRP	UC		

TABLE 5--Western Region Jointly Owned Plants (Continued)

Plants	Location State	Type[1]	Fuel[2]	Unit	Capacity of Unit (MW)	Ownership Company	Ownership Percent	Operator	Status[3] as of January 1980	Inservice Date (year)	Comments
Pebble Springs	OR	NU	UR	1	1260	PGE	40.0	PGE	P	1988	
						PPL	25.0				
						PSPL	20.0				
						PNWG	10.0				
						Uncommitted	5.0				
Allen	NV	ST	C	1	500	NEVP	8.0	NEVP	P	1986	
Allen	NV	ST	C	2	500	PG&E	46.0	NEVP	P	1987	
Allen	NV	ST	C	3	500	SCE	46.0	NEVP	P	1988	
Allen	NV	ST	C	4	500			NEVP	P	1989	
Calif. Coal	CA	ST	C	1	500	SCE	50.0	SCE	P	1988	
Calif. Coal	CA	ST	C	2	500	ANHM	3.1	SCE	P	1989	
						BURB	1.7				
						CDWR	8.8				
						COLTON	0.7				
						GLEN	1.7				
						IID	2.3				
						LDWP	20.3				
						NEVP	7.3				
						PASA	1.7				
						RVSD	2.4				
Intermountain	UT	ST	C	1	750	LDWP	34.1	LDWP	P	1986	
Intermountain	UT	ST	C	2	750	AHHM	10.2	LDWP	P	1987	
Intermountain	UT	ST	C	3	750	BURB	1.7	LDWP	P	1988	
Intermountain	UT	ST	C	4	750	GLEN	1.7	LDWP	P	1989	
						PASA	3.4				
						RVSD	6.8				
						ICPA	17.1				
						UPLC	25.0				
Laramie R.	WY	ST	C	1	500	BEPC	42.0	BEPC	UC	1980	
Laramie R.	WY	ST	C	3	500	TSGT	24.0	BEPC	UC	1982	
						Missouri Basin Muni.	17.0				
						Lincoln Electric	13.0				
						Heartland Cons	3.0				
						WY. Muni. Power	1.0				
Pawnee	CO	ST	C	2	470	PSC	74.5	PSC	P	1987	
						Uncommitted	25.5				
Reid Gardner	NV	ST	C	4	250	NEVP	32.2	NEVP	P	1983	
						CDWR	67.8				
Southeast	CO	ST	C	1	470	PSC	80.9	PSC	P	1985	
Southeast	CO	ST	C	2	470	ARPA	8.5	PSC	P	1986	
						Uncommitted	10.6				
Southwest	CO	ST	C	1	400	CUEA	55.0	CUEA	P	1988	
						Uncommitted	45.0				

TABLE 5--Western Region Jointly Owned Plants (Continued)

Plants	Location State	Type[1]	Fuel[2]	Unit	Capacity of Unit (MW)	Ownership Company	Ownership Percent	Operator	Status[3] as of January 1980	Inservice Date (year)	Comments
United Central Co.	CO	ST	C	1	470	PSC	53.0	PSC	P	1988	
						Uncom-mitted	47.0				
Valmy	NV	ST	C	1	250	SPP	50.0	SPP	UC	1981	
Valmy	NC	ST	C	2	250	IPC	50.0	SPP	UC	1984	
Warner Valley	UT	ST	C	1	250	NEVP	25.0	NEVP	P	1985	
Warner Valley	UR	ST	C	2	250	PG&E	25.0	NEVP	P	1986	
						SCE	25.0				
						STGR	25.0				

[1]Type: HY - Hydroelectric
NU - Nuclear
ST - Steam

[2]Fuel: C - Coal
FO6 - No. 6 Fuel Oil
PL - Plutonium
UR - Uranium

[3]Status: E - Existing
P - Planned but not under construction
UC - Under construction

[4]WPPSS plants are jointly owned by 19 PUD's and 3 municipal utilities. The output is controlled by and delivered into the BPA system.
SOURCE: WSCC Reply to DOE Form 411, of April, 1980.

CHAPTER 3
COORDINATION IN THE NORTHWEST POWER AREA

INTRODUCTION

The Northwest Power Area is the largest of the four subregions of the Western Region in geographical area and generating capability. The subregion under consideration coincides with the service area of the Northwest Power Pool (NWPP), less that portion of the NWPP that is in the Canadian Provinces of British Columbia and Alberta. Although it is not the purpose of this study to consider utility coordination beyond the boundaries of the United States, a discussion of the NWPP must, of necessity, include some data with respect to the NWPP's Canadian members. In addition to the operations of the NWPP, this chapter addresses coordination that is achieved through the several other major coordinating groups within the subregion, through bilateral arrangements, and through transactions with utilities in other subregions within the Western Region. The coordinating groups addressed in this chapter are the following:

- The Northwest Power Pool
- The Pacific Northwest Utilities Conference Committee
- Pacific Northwest Coordination Agreement
- The Mid-Columbia Hourly Coordination Agreement
- Intercompany Pool
- The Public Power Council
- The Public Generating Power Pool

There are 43 generating entities in the U.S. portion of the Northwest Power Area, including the two Federal agencies whose power is marketed by the Bonneville Power Administration (BPA). Table 6 gives the installed capacities and 1978 peakloads for utilities with 200 MW or more installed capacity.

BRIEF HISTORY OF INTERCONNECTION

Interconnection among the utilities of the Northwest began in 1917, with the first tie between the Washington Water Power Company and the Pacific Power & Light Company. Through the 1920's and 1930's, additional connections were made, but it was the development of the Bonneville Power Administration system, beginning in the

TABLE 6--Northwest Power Area Generating Utilities (U.S. Only)[1]

Utilities with 200 MW or More Installed Capacity	Installed Capacity 1978 (MW)	Peakload 1978 (MW)
Water and Power Resources Service (PN Region)	5,096	(2)
Chelan County PUD	1,682	412
U.S. Army Corps of Engineers	11,387	(2)
Douglas County PUD	774	120
Grant County PUD	1,620	257
Idaho Power Co. (Main & Salmon Systems)	1,412	1,853
The Montana Power Company	1,431	1,152
Pacific Power & Light Company	4,812	3,507
Portland General Electric Company	2,681	2,796
Puget Sound Power & Light Company	483	3,284
Seattle City Light Department	1,307	1,592
Tacoma City Light	660	825
Utah Power & Light Company	2,736	2,102
The Washington Water Power Company	829	1,543

[1]Excludes 29 other utilities with generating capacities less than 200 MW.

[2]Marketed by Bonneville Power Administration. BPA 1978 peakload was 10,200 MW.

SOURCE: FPC Forms 1 and 12.

early 1940's, which formed the high capacity grid necessary for truly regional coordination. By the end of World War II, the BPA system solidly tied together the utilities of Oregon and Washington. The systems of Montana, Idaho, and Utah, although interconnected with the western utilities, were tied to those utilities with relatively weak links during the next 15 years. British Columbia Electric Company (later British Columbia Hydro & Power Authority) was strongly tied to BPA by 1949.

From 1942 until the early 1960's, the utilities of the NWPP along with the Rocky Mountain Power Pool (Eastern Montana, Wyoming and Colorado) formed an isolated interconnection, that is, they were not interconnected with any utilities outside of the two areas. The membership of the pool's Operating Committee, even in 1979, reflects those same eastern boundaries. During the 1960's, however, new interconnections were made in many directions. On the eastern side of the pool, Utah Power & Light Company was tied to the Arizona-New Mexico utilities at Four Corners and Glen Canyon, and the Arizona-New Mexico utilities, in turn, were tied to the systems in southern California. The NWPP, as stated above, was already interconnected at several points to utilities operating in Wyoming and Colorado. On the western side, the Pacific Interties (two 500-kV a-c circuits and one 800-kV d-c line) were constructed,

forming a high-capacity, north-south link between the NWPP and California. The resulting Western Interconnected Systems were, for a time, interconnected with the Eastern Interconneced Systems, but the attempt to hold the systems of the North American continent together through the relatively weak interfacing systems was found impractical.

Transmission paths among the utilities of the Northwest Power Pool continue to be strengthened, with the primary emphasis today placed on augmenting the transfer capability between the coal-fired generating plants in Montana and Wyoming and the load centers of the Pacific coast.

THE IMPORTANCE OF HYDROPOWER

The Northwest is a unique region from a power supply standpoint because of its hydroelectric base. During the 1978-79 operating year, about 75 percent of the electric energy requirements of NWPP utilities were expected to be met by hydroelectric generation, and hydroelectricity did account for 79 percent of the peakload in January 1979.

Most electric utilities in the United States grew in concentrated fashion around their load centers. Their generating plants tended to be located as near as possible to load, for reasons of economy and reliability. This pattern was followed in the Northwest prior to the massive development of the Columbia River; utilities built hydroelectric plants on nearby streams. For example, Seattle City Light developed the Skagit River, the Washington Water Power Company constructed facilities on the Spokane River, and Tacoma City Light built its plants on the Nisqually and Skokomish Rivers. In this mode of expansion, transmission systems were densely centered about heavily populated areas, and interconnections among utilities were generally low-capacity lines. These interconnections were useful in taking advantage of the various diversities that existed among the individual systems.

As the Federal Government started development of the Columbia River, particularly with the building of Grand Coulee, the pattern of local concentration of generation changed in the Northwest. The Bonneville Power Administration had customers in all the major population centers of Oregon, Washington, northern Idaho, and western Montana, while generating resources were remotely located from all of them. The result was a need for a high-capacity transmission grid which, by the midforties, was capable of moving large amounts of power among all the utilities of the region. Wheeling of electric energy across third-party transmission, especially the BPA system, became commonplace in the 1950's. Thus, the exploitation of a distant energy resource by a regional entity provided the utilities of the Northwest a unique vehicle for pooling and coordinating their energy production.

Because of its dependence on precipitation and snowmelt, hydroelectric generation is characterized by both predictable and unpredictable cycles of water availability. The cycles can be controlled somewhat by providing water storage in large reservoirs. Such reservoirs have been built as part of some hydroelectric projects in Canada and the U.S., but even today there is not enough storage capacity in the Northwest to regulate streamflows to their long-term average values. Facing uncertain future streamflows, each utility must manage its reservoir storage to ensure meeting future loads. Spilling of water for lack of reservoir storage is, of course, a total waste of a valuable resource. In the pool's early history, procedures were developed whereby any utility could exchange energy so as to store water in the reservoirs of another system for later recall. Because of the diversity of runoff patterns in the various streams of the Northwest, transfers of storage energy among the utilities have been frequent.

Hydroelectric projects on the Columbia River and its tributaries have been built by many of the utilities of the Northwest. The fact that upstream regulation by one utility affects all downstream plants--for example, water released at the Water and Power Resources Service's Hungry Horse Reservoir affects the generation of every other pool utility, except Utah Power & Light Company, Idaho Power Company, and Calgary Power, Ltd., before it reaches the ocean--adds another dimension to the reservoir management problem. Diverse ownership of hydroelectric projects on a single river has been the cause for several coordinating efforts in the Northwest; all involving coordinated operation and transfers of energy among the systems.

The diverse ownership of hydroelectric projects also presents some impediments to more complete pooling. Most non-Federal hydroelectric projects are operated under license provisions, while Federal plants are subject to the conditions of authorizing legislation. Nearly all hydroelectric projects have additional nonpower constraints imposed by governmental authority. Because project owners may not delegate these responsibilities to others, the ability to turn control of these facilities over to a single dispatch center is limited. But the most important impediment is economic. In a hydroelectric system with seasonal storage, the objective is to utilize available water to carry estimated loads throughout the entire reservoir drawdown period and to ensure refill for the next drawdown period. In a pool based on thermal generation, the most economic dispatch can be determined instantaneously. It is relatively easy to perform the dispatch and to allocate costs and benefits among the pool members. However, in a hydroelectric system the value of an incremental unit of hydroelectric energy will vary with time. That unit of energy may be generated at a certain time at one value, or it may be conserved in the reservoir for later use at another value, which can only be determined at the time it is used. Formulation of a central

economic dispatch for the Northwest Power Pool would be difficult, but achieving a satisfactory scheme for allocating costs appears to be virtually impossible.

MEANS OF COORDINATION

Northwest Power Pool membership reflects conditions that prevailed between the time when real intraregional interconnection began early in World War II, due to requirements of the War Production Board, and the time when ties to other parts of the West were constructed in the midsixties. During the early years the pool was an isolated interconnection, and the membership's objective was to deal with those operating issues that arise from the fact of interconnection. These issues include such things as interchange scheduling and accounting, generation and voltage control practices, operating reserve, and emergency actions. The practice of handling most interchanges as bilateral transfers has been maintained consistently in all arrangements among the utilities of the NWPP.

In the early years of the NWPP, transfer capability between the eastern and western parts of the pool was quite small--too small to permit substantial interchanges. For purposes of evaluating resource adequacy, the pool was divided into an East Group and a West Group. This division also provided a way of separating those utilities in the United States dependent upon the Columbia River, its northern tributaries and coastal streams (the BPA marketing area), from other NWPP systems. Even though many years have passed since the initial cause of the east-west separation, the segregation has been maintained as a basis for load-resource analyses.

The Pacific Northwest Utilities Conference Committee (PNUCC), which was established after World War II to support coordinated, regional power supply planning, publishes annually its West Group Forecast of Power Loads and Resources. As the utilities of the West Group become participants with East Group utilities in coal-fired generating plants located in the East Group area, the distinction between the two groups becomes less meaningful for resource planning purposes, and modifications of this structure are currently being considered.

The Pacific Northwest Coordination Agreement (PNCA) has been in effect since 1964 and supersedes several short-term agreements that began in 1961. The agreement is an extremely complex and rather comprehensive contract, the primary function of which is to formalize the seasonal operation of the hydroelectric system. Under the PNCA, planning of reservoir operation is performed on a "single-owner" basis, and it provides all parties the assurance of reservoir operation according to that plan. It establishes rights and obligations to transfers of energy among the utilities to make up the discrepancies between the pooled operation and individual utility needs, and between planned and actual reservoir operation. The most important incentive for the agreement was the Columbia

River Treaty, between Canada and the United States, pursuant to which three large reservoirs on the headwaters of the Columbia River in Canada and the Libby project in western Montana were built and are operated. The parties to the PNCA are almost the same as the West Group utilities--those systems affected by regulation of the Columbia River, its northern tributaries and coastal streams.

The Mid-Columbia Hourly Coordination Agreement, in effect since the early 1970's, provides for the continuous coordination of seven hydroelectric projects on the mid-Columbia River. Parties to the agreement include utilities affected by those projects. The seven plants are very closely linked hydraulically, and this agreement effectively operates all seven as a unit to meet the pooled requirements of the parties.

The Intercompany Pool (ICP) was formed in 1947 with the four West Group investor-owned utilities as members. It was expanded in 1973 to include all seven of the investor-owned utilities in the United States portion of the Northwest Power Pool.

Table 7 shows the participation of Northwest utilities and agencies in the various organizations and agreements that have been established to carry out coordinating efforts.

COMMUNICATION, SCHEDULING, AND BILATERAL TRANSFERS

Heavy use of interconnections for transfers of power has been a way of life for the electric utilities of the Northwest for almost 40 years. Over these years the systems have developed channels of communication and continuous close contact so that the availability of energy for sale by one, or the need for assistance by another, is widely known almost instantly.

Evidence of this dependence on interchanges of power is given by the multiplicity of contracts between Northwest utilities. These utilities also pioneered in the creation of power scheduling as a job function, separated from power system dispatching. All of the major utilities in the region have staffs of power schedulers whose full-time job is to arrange scheduled transfers of energy with other interconnected systems; Bonneville Power Administration has schedulers on duty around the clock. In addition, joint scheduling offices have been established at BPA's Dittmer Control Center for handling transactions with the Southwest over the Pacific Intertie, and at the Intercompany Pool office in Spokane to allocate energy made available to the investor-owned utilities as a group and to arrange schedules among themselves.

Although most schedules in the Northwest are bilateral, and might give the appearance that Utility A has dealt with Utility B in a communications vacuum, many of the transfers implement the pooling features of multiparty contracts, and others result from opportunities that have been known and shared by all utilities.

TABLE 7--Participation of Northwest Utilities and Agencies in Various Organizations and Agreements

Utility or Agency	Common Abbreviation	Organization or Agreement: Northwest Power Pool	Pacific Northwest Coordination Agreement	Western Systems Coordinating Council	Pacific Northwest Utilities Conference Committee	Mid-Columbia Hourly Coordination Agreement	Intercompany Pool
Investor-owned Utilities							
Colockum Transmission Company, Inc.	Colockum		X			X	
Idaho Power Company	IPC	X		X			X
Pacific Power & Light Company	PP&L	X	X	X	X	X	X
Portland General Electric Company	PGE	X	X	X	X	X	X
Puget Sound Power and Light Company	PSPL	X	X	X	X	X	X
The Montana Power Company	MPC or MPCo	X	X	X	X		X
The Washington Water Power Company	TWWP or WWP	X	X	X	X	X	X
Utah Power & Light Company	UPL	X		X			X
West Kootenay Power & Light Company, LTD.	WKPL	X		X			
Calgary Power, Ltd.	CPL	X		X			
Public Agencies							
British Columbia Hydro & Power Authority	B.C. Hydro	X		X			
Eugene Water & Electric Board	EWEB	X	X	X	X		
PUD No. 1 of Chelan County, Washington	Chelan	X	X	X	X	X	
PUD No. 1 of Cowlitz County, Washington	Cowlitz		X	X	X	X	
PUD No. 1 of Douglas County, Washington	Douglas	X	X	X	X	X	
PUD No. 1 of Pend Oreille County, Washington	Pend Oreille		X		X		
PUD No. 2 of Grant County, Washington	Grant	X	X	X	X	X	
Seattle City Light	SCL	X	X	X	X	X	
Tacoma City Light	TCL	X	X	X	X	X	
Washington Public Power Supply System	WPPSS	X			X		

TABLE 7—Participation of Northwest Utilities and Agencies in Various Organizations and Agreements (Continued)

Utility or Agency	Common Abbreviation	Organization or Agreement: Northwest Power Pool	Pacific Northwest Coordination Agreement	Western Systems Coordinating Council	Pacific Northwest Utilities Conference Committee	Mid-Columbia Hourly Coordination Agreement	Intercompany Pool
Federal Agencies							
Bonneville Power Administration	BPA	X	X[1]	X	X[3]	X	
Water and Power Resources Service	WPRS	X	X[2]	X			
U.S. Army Corps of Engineers, North Pacific Div.	USCE-NPD	X	X[1]	X	X[3]	X	
Others							
26 Western Utilities				X			
8 Northwest PUD's; 3 Northwest Municipal Systems					X		

[1]BPA, acting for the Department of the Interior, and the U.S. Army Corps of Engineers, acting for the Department of the Army, signed the agreement as representatives of the United States of America and the United States Entity.

[2]The Water and Power Resources Service (formerly the Bureau of Reclamation), although not a signator of the Coordination Agreement, is represented on the Coordination Contract Committee.

[3]Represented, but not a member.

SOURCE: BPA, Division of Power Management, Branch of Power Supply.

JOINT PARTICIPATION POWERPLANTS

The need and timing for new power-generating facilities are published on a regional basis in the Northwest, through the PNUCC. The output of every existing and planned baseload thermal plant is shared by two or more utilities through purchase of a portion of the plant's production, through joint ownership, or through net billing with the Bonneville Power Administration. Committees of owners and purchasers are established for each of these plants, with the result that construction, operation, and maintenance of these facilities are fully coordinated. According to the PNUCC West Group Forecast, almost half the electric energy supply of the West Group will be produced under adverse hydro conditions by these joint-participation facilities by 1990.

Besides the baseload thermal plants, the five non-Federal mid-Columbia hydroelectric projects (combined capacity of almost 4500 MW) have widely diversified participation. One of these, Rock Island, was built long before there was a Northwest Power Pool, and the others were placed in service starting in the late 1950's. Grant County Public Utility District (PUD) owns Priest Rapids and Wanapum, Chelan County PUD owns Rock Island and Rocky Reach, and Douglas County PUD owns Wells.

EXISTING COORDINATION WITHIN THE NORTHWEST POWER AREA

THE NORTHWEST POWER POOL

Interconnected operation in the Pacific Northwest preceded the formation of the Northwest Power Pool (NWPP) by 25 years. Later, additional connections were established for transferring firm power, utilizing diversity among resources, providing emergency reserve, and for economy interchanges.

Following the interconnection of Utah Power & Light in 1941, a six-company pool was formed, composed of Northwestern Electric Company, Pacific Power & Light Company, the Washington Water Power Company, the Montana Power Company, Utah Power & Light Company, and Idaho Power Company. A coordinating office was established in Portland.

In 1942 the NWPP was created as a result of War Production Board Order L-94, issued shortly after the United States entered World War II, directing utilities throughout the country to cooperate among themselves in order to increase the electric capacity to meet added wartime loads. After the war, the participating utilities decided that the gains which had been realized through coordinated operation were so beneficial that the pool should be continued on a voluntary basis.

The Northwest Power Pool membership includes eight publicly owned U.S. utilities (including BPA) with a total generating capacity of 27,272 MW, seven investor-owned U.S. utilities with a

total capacity of 11,773 MW, one Canadian public utility with 7440 MW of capacity, and two privately owned Canadian utilities with a combined capacity of 2719 MW. (These figures are effective for July 31, 1979.) The membership of the NWPP is given in Table 6. Total installed peaking capacity of NWPP members is 49,204 MW. (See Figure 6.) All power pool members are generating utilities.

The power pool service area, shown in Figure 7, includes all of Washington, Oregon, Utah, Idaho, Montana as far east as Billings, small portions of Wyoming along its western border, and similarly small strips along the northern borders of California and Nevada. The Canadian members of the pool serve all loads in British Columbia and approximately two-thirds of the peakload in Alberta.

Bonneville Power Administration serves 116 publicly owned utilities including 36 municipalities, 26 publicly owned utility districts, and 54 cooperatives. (See Figure 8.) It also serves 8 privately owned utilities, 17 direct service industries, 6 Federal agencies, and 14 organizations outside the Pacific Northwest. Several publicly owned utilities are served by the other members of the Northwest Power Pool. In the United States and Canada, the power pool includes or serves 18 privately owned utilities. (See Figure 9 for the service areas of the privately owned utilities.)

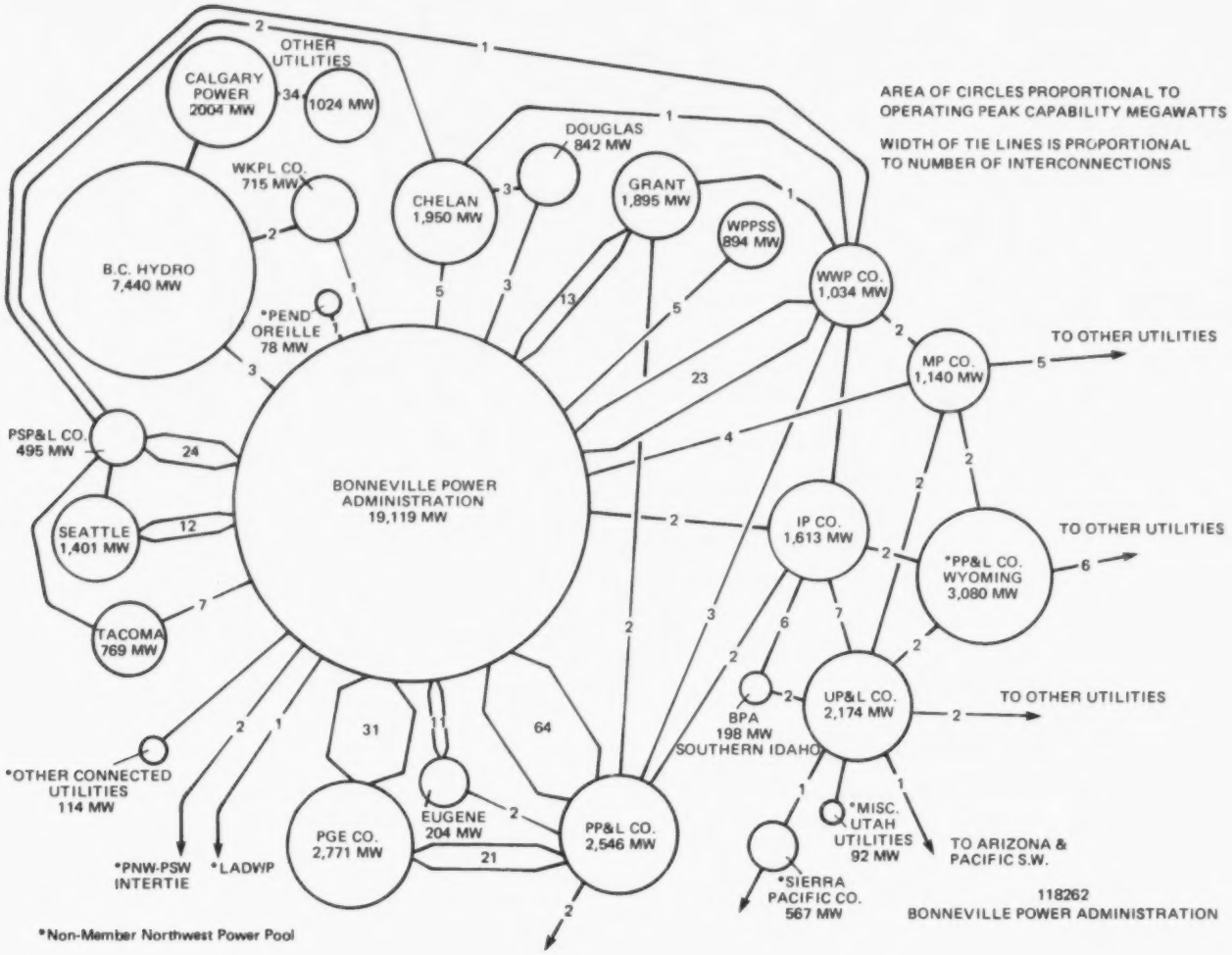
Because electrical heating is common in the Pacific Northwest, peakloads on the Northwest power system occur in winter. Peak streamflows used to refill reservoirs occur in the spring. For these reasons planning is done for a July 1 through June 30 operating year and reports are organized accordingly.

Approximately 80 percent of NWPP members' installed capacity consists of hydroelectric generators. Of the remaining capacity in the 1977-78 operating year, 7250 MW was conventional (non-nuclear) generation, 870 MW was obtainable from combustion turbines, 610 MW was combined cycle generation, 12 MW was due to diesel engine generators, and 1868 MW was available via steam from nuclear reactors. See Figure 10 for a display of the main Northwest Power Pool members' transmission facilities.

The Northwest Power Pool is a totally voluntary organization--a confederation of autonomous electrical systems, without a central authority. The governing body of the pool is the Operating Committee, which has a permanent staff, the Coordinating Group.

The Operating Committee consists of 20 members--one representative from each participating system--through whom all pool matters are handled. Implementation of any pool action requires unanimous approval of the committee. In its more than 25 years of substantial achievement, the Operating Committee has never had to take a formal vote. Each representative has the right to call in as many members of his organization as he desires for consultation, but he alone is the official spokesman for his system in all considerations.

The Coordinating Group, located in Portland, is composed of five engineers and three clerks. The group is delegated no authority,



Notes:

1. Width of tie lines is proportional to number of interconnections.
2. Area of circles proportional to operating peak capability megawatts. Peak generating capability is a total from the FERC Form 12 Reports. Jointly owned capacity is not included unless the plant is also operated by the listed utility.

FIGURE 6--Northwest Power Pool Interconnections as of July 1, 1979

FIGURE 7--Northwest Power Pool Service Area

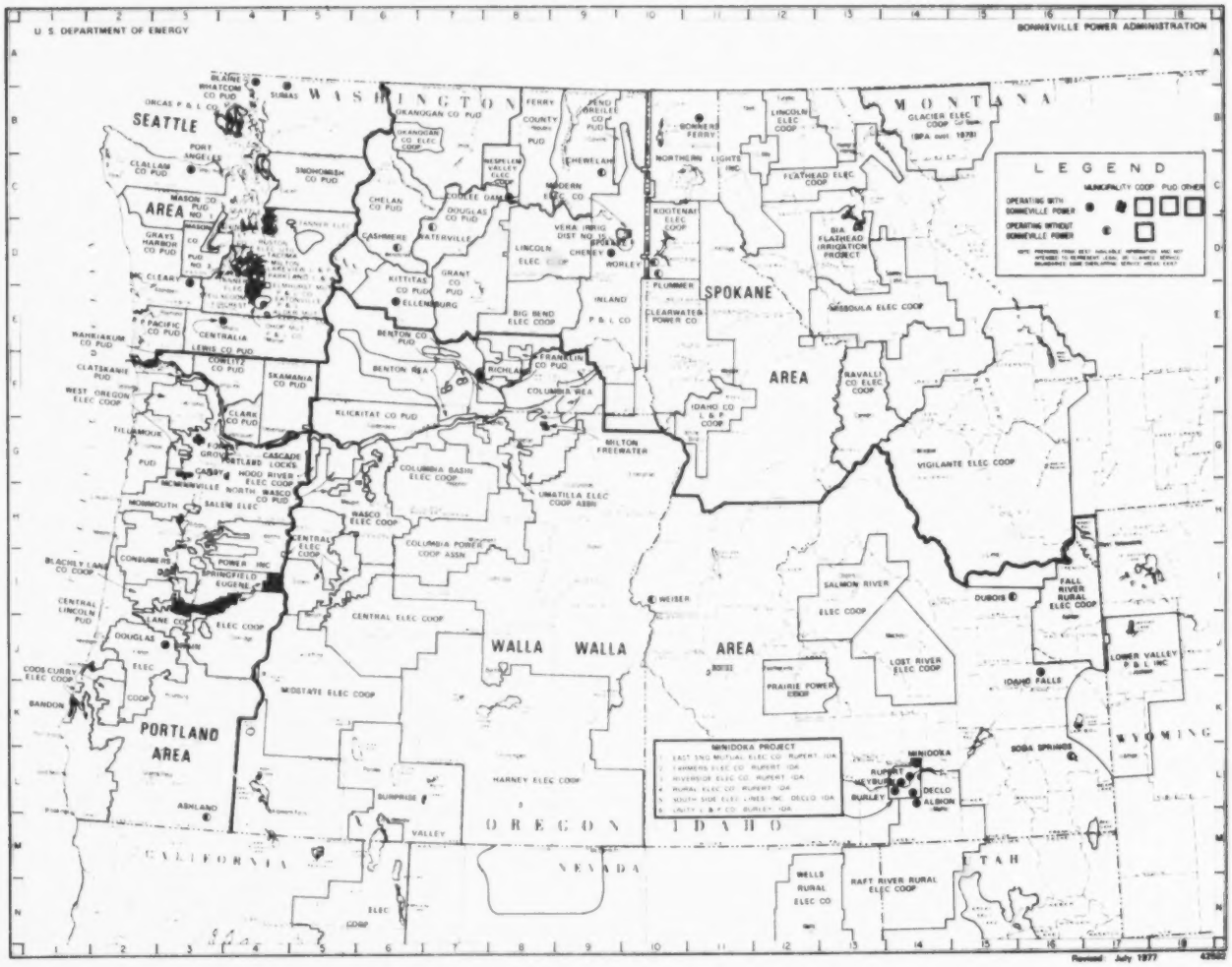


FIGURE 8--Service Areas--Operating Public Agencies and Cooperatives-NWPP

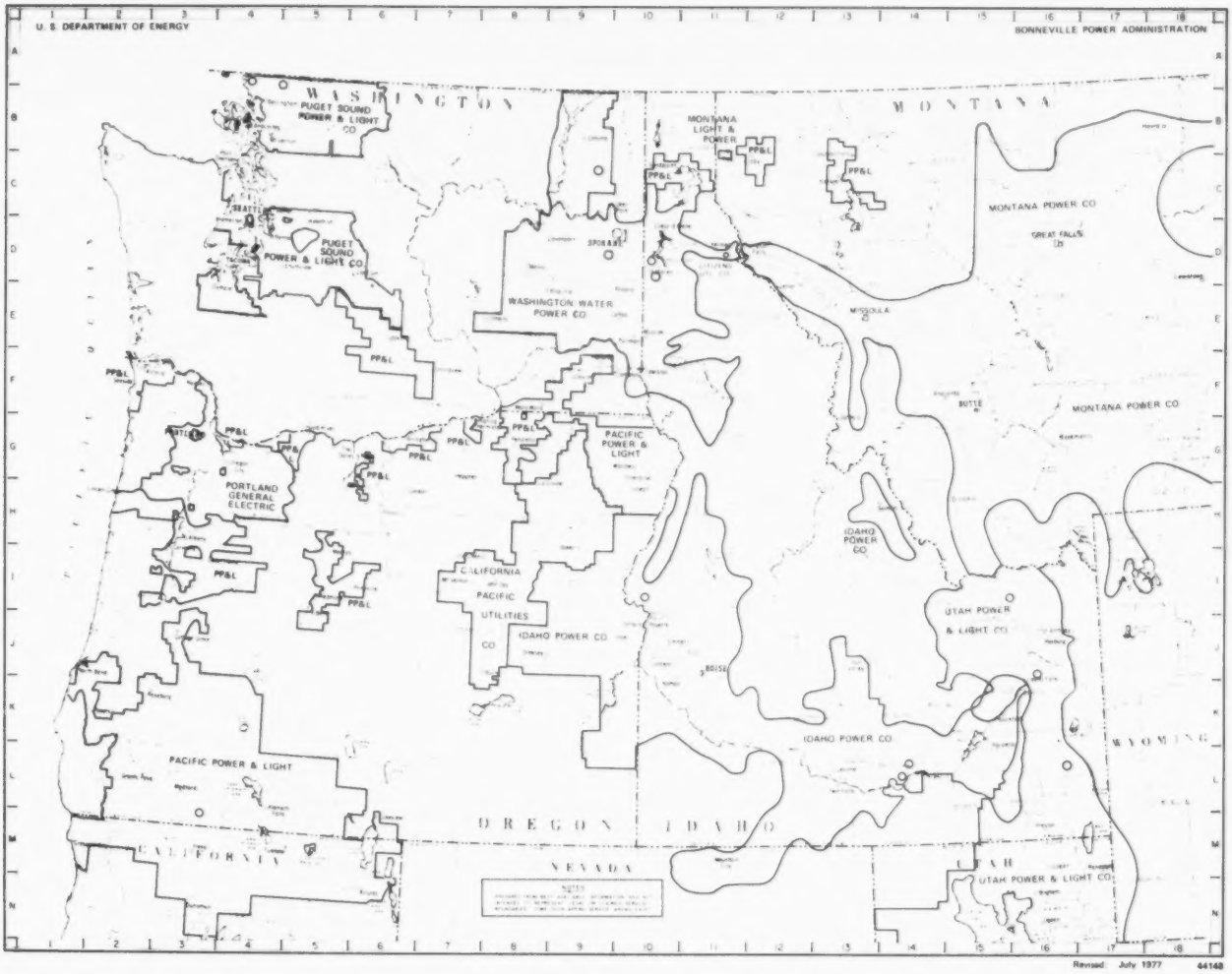


FIGURE 9--Service Areas--Investor-Owned Utilities-NWPP

FIGURE 10--Principal Transmission Lines in Northwest Power Pool Service Area

but act as consultants to the Operating Committee by arranging conferences, conducting meetings, preparing operating and other programs, producing reports, and making operating studies (including those required by the coordinating contract), as directed by the Operating Committee. The Coordinating Group also acts as an information clearinghouse for the entire pool. In this capacity it assembles and publishes the results of many coordinated activities, including the following:

- The Pool Principles and Procedures
- The annual Operating Program
- The annual Operations Review
- The Pool Underfrequency Load Shedding Program
- Power and Reactive Tests of actual operation
- Communication and Telemetering Channels
- Maintenance Schedules
- Headwater Reservoir Payments

The group collects and prepares data required of Northwest Power Pool utilities by WSCC and NERC. It also conducts the studies and systems monitoring prescribed by the Pacific Northwest Coordination Agreement.

The Operating Committee functions through many subcommittees, which have been established to treat specialized problem areas. These subcommittees frequently have specialists as members, as well as members of the Operating Committee.

THE PACIFIC NORTHWEST UTILITIES CONFERENCE COMMITTEE

The Pacific Northwest Utilities Conference Committee (PNUCC) was first established in the mid-1940's, and comprised both investor-owned and publicly owned electric utilities with an interest in generating facilities. The committee worked with various Government agencies in matters relating to the planning, construction, and coordinated development of Federal projects associated with the U.S. Columbia River Power System and presented to Congress the views of the non-Federal electric utility industry in the Pacific Northwest relative to various Federal appropriations affecting the power supply of the Northwest region. Later, as it became apparent that future problems in the utility industry would affect vital interests of both generating and nongenerating facilities, there developed a need for a broader representation of the region's utilities. Thus, a policy committee was formed consisting of representatives of public agencies, direct-service industries, investor-owned utilities, BPA, and the Corps of Engineers with an interest in PNUCC activities, who may or may not be members of the PNUCC organization.

One of PNUCC's main activities during the last few years has

been the Loads and Resources Subcommittee preparation of the West Group Forecast, which is a comparison of the region's total electric requirements and its total electric resources. The overall direction of activities comes from the Policy Committee and from the technical guidance and coordination of the System Planning Committee and its technical staff. An executive committee was recently established consisting of nine members, three appointed by the public agency and cooperative members of the Policy Committee, three by the private utility members, and three by the direct service industry members. The Bonneville Power Administration and the Corps of Engineers are also represented on the committee. Additionally, the four Northwestern States (Washington, Oregon, Idaho, and Montana) have been invited to participate. Many other committees, subcommittees, and task forces, some of which are inactive from time to time but reorganize as the need arises, also exist.

Policy Statement on Systems Planning Committee--Necessarily, regional energy planning must continuously be improved, both in terms of the elements to be weighed and the governmental and nongovernmental interests that should participate in the planning process. To help foster such improvements, PNUCC has sponsored the Systems Planning Committee, a small committee of top level technical officers. Representatives of BPA, the U.S. Army Corps of Engineers, and the governments of the four Northwest States, along with representatives of the public and private electric utilities and the direct-service industrial customers of BPA, have been invited to participate fully.

The committee and its various subgroups and task forces are seeking solutions to the technical and economic problems involved in regional energy planning. The work being pursued includes load analysis and forecasting; conservation opportunities and effects; new resource needs, types, characteristics and timing; and systems analyses of how new developments and strategies can be incorporated in the existing regional power system. This work is intended to provide objective information of use to everyone, without committing any organization to any specific result. Individual Federal, State, or utility plans and analyses will, of course, continue to be the province and responsibility of each organization.

The work of the committee, and the several task forces that will be established from time to time, is intended to be a continuing effort through which interested parties, not limited to those specifically represented on the committee, can influence energy planning trends at an early and effective stage.

System Planning Office--An office staff of six professionals and supporting clerical help has been established in Portland, Oregon, to assist in carrying out the programs of the System Planning Committee. The staff will supplement, but not replace, the current task force efforts, and is intended to accelerate progress in

several vital and ongoing regional planning efforts. These activities include the following:

1. The annual preparation of a regional electric sales forecast, as well as continued development of the econometric forecasting model
2. Design and conduct of a regional end use data survey to develop a data base for conservation and other studies
3. Annual preparation of the West Group Forecast, which compares the planned resource of the region with the projected loads
4. Development of improved planning techniques for the region, which has unique planning requirements because of the large amount of hydro storage and capacity
5. Development of alternative regional resource and conservation plans to assess costs and environmental implications of each

Regional planning standards are set for purposes of including resources in the West Group Forecast. These standards include both milestones for indicating the time when resources will be included as a regional resource and limits on the energy production of future plants, which will be included as a regional resource.

PACIFIC NORTHWEST COORDINATION AGREEMENT

In September 1964, following more than a decade of negotiations and after several preliminary, short-term agreements, 16 Pacific Northwest utilities signed the Pacific Northwest Coordination Agreement (PNCA), a long-term contract (effective until 2003) providing for coordination of the seasonal operation of resources, particularly hydroelectric resources. Aside from the need to formalize established Northwest Power Pool practices and principles in binding terms, formulation and acceptance of the PNCA were necessary to establish rights, obligations, and procedures associated with the terms and benefits of the United States-Canada Columbia River Treaty, which also became effective in 1964.

Of the 16 parties to the agreement, Cowlitz County PUD, Pend Oreille County PUD, and the Colockum Transmission Company, Inc., are not members of the Northwest Power Pool. Six of the current members of the NWPP are not PNCA signatories. The North Pacific Division Engineer and the Bonneville Power Administrator, acting together, executed the agreement twice, once representing the United States of America and again as the United States Entity provided for by the Columbia River Treaty. The 14 other utility parties to the agreement are listed in Table 7. All signatories control power generating facilities within the Pacific Northwest.

The PNCA reduced to the form of contractual obligations many of the coordination practices that were in effect on a voluntary basis among the members of the NWPP before the 1960's. Basically the

agreement calls for the coordinated operation of the generation facilities, transmission facilities, and reservoirs of all the parties in order to achieve as closely as possible the capability of a single system to meet firm energy and peakload.

The methods for achieving this coordinated operation consist of the advance preparation of each annual operating program in which the total reservoir and hydroelectric generating system is operated, without regard to ownership, to maximize firm energy load-carrying capability. After this step, individual parties may make certain changes that have the effect of improving the planned operation of their system and reducing the coordinated system's firm energy load-carrying capability slightly below its maximum.

Operations during each year consist of exchanges of energy and capacity to account for diversities in streamflows, loads, and generator-forced outages. Energy is also exchanged between reservoir operators and other parties who operate generating facilities downstream from each reservoir to achieve coordinated operations of the reservoirs. Although some payments for imbalances of energy or capacity may be required, the PNCA basically does not provide for any firm or secondary power sales among the parties. Each party continues to plan and control the operations of its own resources. Exchanges of power are accomplished by scheduling energy between the load control areas of each party. With this type of coordination, the ownership identity of power is retained instead of pooling the energy and determining each party's consumption at the end of a billing period.

Annual payments for benefits derived from releases of water from upstream reservoirs, similar to the requirements under Section 10(f) of the Federal Power Act, are provided by the agreement. The PNCA also provides for a Coordination Contract Committee, which is responsible for preparing the annual operating plan and other studies. The committee receives technical assistance from the Northwest Power Pool Coordinating Group. The PNCA does not cover long-range planning of new resources; and, having been developed before the Pacific Northwest depended on large thermal generating plants, the agreement does not coordinate the operation of such plants.

Although many PNCA objectives are common to pooling arrangements among utilities elsewhere in the United States, several of the agreement's major procedures are unique. These unique features are due to the preponderance of hydroelectric generation in the Pacific Northwest, and the fact that energy supply, rather than installed generating capacity, limits ability to serve firm load.

When the agreement was signed in the early 1960's, it was credited with increasing the coordinated system's capability to meet firm load by more than 1000 MW. It also provides some assurance that third-party transmission service will be available and that energy can be conserved by storing it in reservoirs. The ability of the coordinated system to produce secondary energy is also probably

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enhanced. However, as noted above, most of the benefits that are attributed to the PNCA were already being achieved by informal coordination within the voluntary guidelines provided by the Northwest Power Pool even before the agreement existed.

THE MID-COLUMBIA HOURLY COORDINATION AGREEMENT

The Hourly Coordination Agreement provides for the moment-by-moment dispatch of the seven mid-Columbia hydroelectric projects in a manner similar to the operation of plants owned and operated by a single entity.

The contract has been executed by the owners of the seven plants involved: U.S. Army Corps of Engineers, Water and Power Resources Service, PUD No. 1 of Chelan County, PUD No. 1 of Douglas County, PUD No. 2 of Grant County, the Bonneville Power Administration, and each of the purchasers of power from the mid-Columbia plants owned by the three PUDs. The plants involved in the coordination are: Grand Coulee, Chief Joseph, Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids.

Section 3, General Objectives, appropriately describes the intent of the parties in the negotiation and implementation of this agreement. It reads as follows:

> The Parties agree to coordinate the operation of the Projects so as to achieve the following general objectives--
>
> (a) To obtain increased amounts of electrical power and energy from the total system of Projects;
>
> (b) To enhance the non-power uses of the river by reducing the extent and rate of fluctuations of river levels insofar as practicable consistent with Section 3(a);
>
> (c) To provide flexibility and ease of scheduling generation for the Projects by a method of centralized coordinated scheduling, and to provide flexibility in scheduling and controlling generation of Projects with several purchasers through the use of composite scheduling and accounting procedures.

The agreement is so constituted that each owner and each purchaser retains all rights and obligations as though uncoordinated, and shares in the benefits of the coordinated operation depending upon where and to what extent they occur.

A "Central" has been established where the physical aspects of coordination are concentrated. Central is located at the Grant County PUD at Ephrata, Washington. Communications are established between Central and the dispatching centers controlling the seven dams: Dittmer, which controls Grand Coulee and Chief Joseph;

Douglas at East Wenatchee, which controls Wells; Chelan PUD at Wenatchee, which controls Rocky Reach and Rock Island; and at the center controlling Wanapum and Priest Rapids. Each control center sends signals to Central representing desired generation at its respective projects. Central then sums the total desired generation and, in accordance with operating strategy, determines the optimum coordinated generation level for each project to meet the total desired generation. Central then sends back to each control center a signal "coordination bias" so that each control center can adjust to the desired generation level at each plant. Signals are exchanged and coordination bias is computed every four seconds to follow the load shape.

INTERCOMPANY POOL

Service Area

The service area of the Intercompany Pool (ICP) encompasses the geographic area served by the seven member companies in Washington, Oregon, Idaho, California, Montana, Wyoming, and Utah. (See Figure 9.) ICP membership, member load systems, and resources are shown below.

ICP Pool Membership

Company	Headquarters
Idaho Power Company (IPC)	Boise, Idaho
The Montana Power Company (MPC)	Butte, Montana
Pacific Power & Light Company (PPL)	Portland, Oregon
Portland General Electric Co. (PGE)	Portland, Oregon
Puget Sound Power & Light Company (PSPL)	Bellevue, Washington
Utah Power & Light Company (UPLC)	Salt Lake City, Utah
The Washington Water Power Company (WWPC)	Spokane, Washington

Member System Loads

	1978	
Utility	Peak (MW)	Energy (Avg. MW)
Idaho	1,853	1,180.4
Montana	1,152	719.4
Pacific Power	3,507	1,781.1
Portland General Electric	2,796	1,372.3
Puget Sound	3,284	1,522.4
Utah Power & Light	2,102	1,387.1
Washington Water Power	1,543	814.2

ICP Resources

1979-80 Operating Year
(July through June)

Resource	Peak (MW)	Energy (Avg. MW)
Total Hydroelectric	8,102	3,833
Major Thermal	7,979	6,176
Purchased Capacity & Energy	3,602	1,095
Combustion Turbines	1,443	128
Total Resources	21,126	11,232

Development of Coordination

The ICP was founded August 30, 1947. Coordinated operation was conducted under a series of yearly pooling agreements until a 20-year agreement was signed in 1953. Upon the expiration of this agreement in September 1973, a revised ICP agreement was entered into expanding the four-member pool to seven with the addition of Idaho Power Company, The Montana Power Company, and Utah Power & Light Company. The revised agreement set forth an expanded scope of authority and responsibility for the ICP organization by specifically providing for general provisions of pooling, planning commitments, operating commitments, reserve commitments, and other organizational considerations.

The original agreement was developed to more fully utilize member resources, and to make the use of firm and secondary energy purchased from the Bonneville Power Administration more flexible. Because of the geographic location of the member systems, it became evident that other benefits--including the sharing of plants, seasonal diversity of loads and resources, and reliability--could be derived from pooling. A major consideration in the pooling operation is the use of the regional resources provided by the Columbia River, in which most of the ICP companies have interests.

Organization--The ICP organization, which has permanent headquarters in the WWPC offices in Spokane, is headed by a director who reports to the Intercompany Pool Committee. This committee is composed of representatives from the seven member companies.

Reporting to the director is a staff consisting of planning engineers and schedulers. The scheduling function provides for a coordinated hourly operation of each system's resource to meet its estimated demands. These representatives keep their member companies apprised of current operating conditions, status of resources as to availability and cost, and available market conditions.

Coordination--Because of the regional nature of the Columbia River and the diversity of interest in this resource, in the early fifties it became clear that some type of regional coordination could lend some order to, and secure some benefit from, the coordinated operation of the region's stream flows. The ICP companies were the first to recognize that a pooling of their collective resources to meet their load could benefit the member systems. This collective recognition of the benefits of a coordinated operation of resources was a major factor in the later execution of the Pacific Northwest Coordination Agreement. Early in the development of the ICP, the member companies joined together each year to plan the operation of their resources. If a member system had a surplus or deficiency existing during a particular period of the year, the other member systems would try to make use of the surplus or provide assistance in meeting the deficiency. As a result of this detailed planning and resultant coordinated operations, the members were able to minimize higher cost purchases of outside power.

Special Operating Requirements--The ICP is principally a resource management organization where each member operates its system and its resources autonomously. System limitations and resource operations are coordinated through the designated pool representatives who schedule the hourly operations of the member system resources.

Cost Sharing--The ICP agreement provides for the sharing of the pool's expenses (staff salaries and expenses--including outside consulting fees and special study expenses) on the basis of the size of the member systems' loads as reported in their annual Form No. 12, FERC Report.

Pooling Interactions

Reliability--Individually and collectively, the ICP members subscribe to the principles and criteria of reliability as set forth by the Western Systems Coordinating Council (WSCC). The ICP agreement encompasses the principle of shared reserves as a reliability and capital investment benefit for each member.

Transmission--The ICP recognizes that a critical part of its pooling agreement is planned, orderly development of the member transmission systems. Its coordination with the development of new resources is a hallmark to reliable system operation. The ICP has established a special committee to monitor the development of the member transmission systems, and a full-time transmission engineer is on the staff to assist in the planning and coordination of transmission activities.

Regulations--All members of the ICP operate under the regulation of the State Utility Commission in the States having jurisdiction over their service areas. In addition, all ICP companies are regulated by the Federal Energy Regulatory Commission.

Service Schedules--As a part of the ICP agreement, each member system has filed a service schedule detailing the terms and conditions under which each member system will market surplus, nonfirm energy. These conditions included the cost of energy from each type of resource, along with associated wheeling charges. Members carry on business bilaterally with the exception of purchases of nonfirm energy from other than member systems. In this case, the purchased energy is prorated among the members according to a set formula.

THE PUBLIC POWER COUNCIL

The Public Power Council (PPC) was formed in 1966. PPC comprises 113 Bonneville Power Administration preference customers, including public utility districts, municipalities, and cooperatives. PPC is the power planning and coordinating organization for all of these preference customers. To this end, PPC promotes the common power supply interest of its members and plans with other groups and utilities to meet future power needs for the Pacific Northwest.

THE PUBLIC GENERATING POWER POOL

The Public Generating Power Pool (PGPP) is an organization of seven consumer-owned electric utilities formed for the purpose of making the most efficient use of power resources and facilities owned jointly and severally by the members. On a regular basis, members exchange information regarding power supply, system load, and forecasted area weather data.

The participating member utilities are: the Eugene Water and Electric Board, PUD No. 1 of Douglas County, PUD No. 1 of Chelan County, PUD No. 1 of Cowlitz County, PUD No. 2 of Grant County, the City of Tacoma, and the City of Seattle.

BILATERAL ARRANGEMENTS

Numerous bilateral arrangements between electric generating utilities in the Pacific Northwest contribute significantly to the coordinated operation of utilities in the region. It is possible that bilateral arrangements contribute as much to the coordinated, efficient operation of the electric generating facilities in the region as do all the other formal coordination and pooling

arrangements previously discussed. The strong integrating transmission facilities that link all generating utilities in the Pacific Northwest provide capability for interchanging energy among all generating utilities, and third-party transmission is available almost without exception, subject, of course, to suitable contractual arrangements for payment and compensation of transmission losses.

An example of a bilateral arrangement that contributes to the coordinated, efficient operation of utility systems in the region is the arrangement in effect between the Pend Oreille County PUD and Seattle City Light. Under this arrangement Pend Oreille contracts to sell all of its firm surplus, and under certain conditions, the nonfirm energy produced at its Box Canyon Hydroelectric plant, to Seattle City Light.

There are numerous examples of medium- to short-term bilateral sales of temporary surpluses from systems having such surpluses to other systems needing to purchase power. Presently, B.C. Hydro has such an arrangement to sell energy to The Washington Water Power Company. Cominco, an industrial corporation in Canada, has marketed temporary surpluses through the West Kootenay Power and Light Company to Pacific Northwest industries and utilities under multiparty contracts for 3- to 6-month terms during the past several years.

Arrangements to store energy in reservoirs are also made bilaterally among utilities in the Pacific Northwest that are not parties to the Pacific Northwest Coordination Agreement. BPA and other Pacific Northwest utilities have such arrangements to store in the reservoirs of B.C. Hydro, and there are similar arrangements for B.C. Hydro to store in BPA reservoirs. BPA currently has a two-way storage agreement in force with the Idaho Power Company. Arrangements that permit several California utilities to store in BPA reservoirs are also currently in force.

The sale of nonfirm energy among utilities within the Pacific Northwest and by Pacific Northwest utilities to those outside the region is not included as a part of any of the coordination arrangements previously discussed (with the possible exception of the Intercompany Pool Arrangement). As a result, sales of nonfirm or secondary energy among utilities are handled on the basis of bilateral sales and scheduling arrangements. At times when streamflows are sufficient to permit the production of secondary energy by Pacific Northwest hydroelectric plants, bilateral schedules of secondary energy abound.

All of the BPA's sales of firm energy and capacity to its public agency customers are made on the basis of the customers' "requirements." That is, BPA sells to generating and nongenerating customers only what those customers require to meet their loads after using their own generating facilities, if any. Through this type of sale arrangement, the needs of all of BPA's public agency customers to install and operate firm energy and capacity generating facilities are no greater than they would be if all of the loads of

these customers were met by the resources of a single generating system.

Many of BPA's other firm sales also constitute a form of coordination. For example, BPA has numerous contracts for sale of peaking capacity to Pacific Northwest and Pacific Southwest utilities. Under these contracts, the purchasing utility has certain rights to take power from the BPA system during heavy-load hours and an obligation to return the energy associated with the capacity deliveries during light-load hours. The purchasing utility compensates BPA either by delivering firm energy to BPA or by monetary payment. This type of contract permits the purchasing utility to use a specified amount of capacity on the BPA system to shape its resources to its loads, and thus constitutes a form of bilateral coordination.

EXISTING INTERPOOL COORDINATION

PACIFIC INTERTIE TRANSACTIONS

Much of the Northwest utility coordination with utilities outside of the geographic area of the Northwest Power Pool is enabled by the existence of the Pacific Northwest-Southwest Intertie (Intertie). When this major transmission link between north and south was energized in 1968, an office was established at BPA headquarters for the purpose of coordinating transactions for the Northwest with the Southwest utilities. This office included a representative from the Northwest private power companies. Similar scheduling arrangements were made in California for both the a-c and the d-c links. During the past 11 years of Intertie operation, significant benefits have accrued for both regions because of the coordination of power sales and exchanges through these offices.

To illustrate the various types of power and energy interchanges between these regions, a short discussion of Intertie transactions follows. Examples of transactions that took place during 1979 are used in this discussion to show relative magnitudes of interchanges in each of four major categories: Columbia Storage Power Exchange (CSPE), Centralia-Central Valley Project (CVP) contract, capacity contracts, and nonfirm energy transactions. Almost 95 percent of the 10.9 million MWh delivered to California during this period can be classified as one of these types.

CSPE energy accounted for 5.7 percent of the deliveries made to California during this period. This energy, deriving from the Canadians' share of the benefits resulting from the joint development of the Columbia River, is being purchased by the State of California Department of Water Resources. The contract terminates in 1983, at which time all CSPE energy will be retained by Northwest utilities. In past years several California utilities have shared in the benefits of this firm supply of energy and capacity. Likewise, Northwest entities have found a ready market

for the additional generation made possible by the extensive development of the Columbia River in Canada.

Prior to the construction of the coal-fired thermal plant at Centralia, Washington, the Water and Power Resources Service's (WPRS) Central Valley Project--an irrigation project in California--contracted to purchase a share of the plant's output. Deliveries are made to the WPRS from the Federal system independently of plant output. BPA is reimbursed through receipt of the WPRS share of Centralia generation as it is produced. During 1979, 25.7 percent of the total deliveries to California were in this category. This contract, which terminates in 1981, allowed for the early construction and use of an economically sized thermal plant within the Northwest region. The firm capacity and energy for the Southwest from this contract has displaced significant quantities of oil-fired generation since 1968.

Capacity or peaking contracts, like the CSPE and CVP-Centralia contracts, provide the purchaser firm capacity. The energy, however, is loaned and subject to return within a specified time if the Northwest finds that it is not surplus to its needs. Three types of capacity contracts are currently in effect. One contract provides firm capacity in exchange for firm energy (exchange peaking capacity). BPA presently has contracted to supply five California utilities with 1202 MW of exchange peaking capacity. In each contract, payment for the capacity (surplus peaking capacity) is sold on a term basis with charges varying depending on the term of the agreement. BPA sells firm capacity on a seasonal basis under a second type of arrangement. Portland General Electric has a third type of capacity contract under which it provides capacity during the spring and summer and receives capacity in the fall and winter. Capacity deliveries accounted for 44.9 percent of all deliveries made in 1979. Return of peaking energy plus the capacity payment or exchange energy, account for 83.4 percent of the 4.8 million MWh delivered from California to the Northwest during this same period.

Nonfirm energy transactions, the sale of energy surplus to Northwest needs, made up 18.4 percent of the deliveries to the Southwest during 1979. Surplus energy may be sold to California in two ways. First, it can be sold to BPA, which then sells the energy to Southwest utilities. Second, Northwest utilities may arrange to sell directly to individual California utilities.

During 1979, energy was sold at prices ranging between 3 and 40 mills per kWh. Recently, many of the sales agreements between Northwest and Southwest utilities have contained language that allows the supplier to recall part or all of the energy.

For 1979, 13.3 percent of the energy delivered from California was energy that had been recalled by Northwest utilities. The benefits derived from the sale of surplus energy are essentially economic. These sales provide the Northwest with revenues for energy that would otherwise have been wasted. The Southwest realizes even greater revenue savings when displacing oil-fired generation. There is, of course, the obvious additional benefit of

conserving a nonrenewable resource. Despite the fact that 1979 was not a particularly good surplus year, the surplus energy deliveries to California by BPA alone saved 1.2 million barrels of oil and brought BPA revenues of more than $2.1 million at BPA's surplus energy rate of 3 mills per kWh. Combined BPA and non-Federal nonfirm energy deliveries saved more than 10 million barrels of oil. Since 1968, a net delivery of nearly 140 billion kWh to California over the Intertie has displaced the equivalent of 233 million barrels of oil.

Contracts between BPA and California utilities also contain provisions for emergency or breakdown relief under which BPA or the other party can obtain emergency assistance. There have also been instances where parties at both ends of the Intertie have provided short-term storage of energy.

The above transactions are typical of those that have existed throughout the history of this interregional transmission path. The magnitudes of these transactions vary periodically, particularly those in the nonfirm category. However, the overall history of Intertie operations and aggregate of energy and capacity transactions throughout its life have provided tremendous benefits to both regions.

INTERPOOL COORDINATION BETWEEN NORTHWEST POWER POOL AND ROCKY MOUNTAIN POWER POOL

The boundaries of the Northwest Power Pool and the Rocky Mountain Power Pool (RMPP) overlap because of dual membership of three systems. Utah Power & Light and The Montana Power Company are members of both pools. The Wyoming Division of the Pacific Power & Light Company (PP&L) is included in the RMPP while the main PP&L system is a member of the NWPP. Because of the pooling activities of these systems in both pools, interpool coordination is effectively accomplished.

Many of the planning and operating matters of mutual concern are coordinated under the framework of the Western Systems Coordinating Council (WSCC) organization. The similar problems of a more local nature are considered by the pools or by the affected systems. The bulk of the energy and capacity transactions in this area are executed under the terms of bilateral contractual arrangements. Numerous permissive agreements exist that allow energy transfers up to the limit of the transmission capacity. Such transfers have been scheduled around the east side of the WSCC area for several years. For example, during periods of Northwest surplus, large quantities of storage energy have been scheduled from BPA as far south as Arizona.

As energy and capacity availability has diminished and the cost has gone up, the intensity of transactions has increased. At the same time the lack of adequate transmission capacity between the Montana-Wyoming area and the NWPP has limited the opportunity for

such transactions. In general, power transfers have been and continue to be scheduled between NWPP and RMPP up to the limit of transmission as suggested by economics or other motivating factors such as the desire to conserve oil.

OPPORTUNITIES FOR AND IMPEDIMENTS TO INCREASED COORDINATION--OUTLOOK

The Pacific Northwest region faces potentially damaging power shortages in the near future. Where once the region was able to supply all of its power demand from a mix of low-cost Federal and non-Federal hydroelectric projects, in recent years the region has had to turn increasingly to thermal generation. Ten of thirteen thermal plants scheduled for installation during the next decade have been delayed. Consequently, even though utility forecasts each year show less future demand than the previous year's forecast, the predicted shortages get larger with each new forecast.

In the Pacific Northwest alone, BPA markets more than 50 percent of the total electric energy requirements. In 1976 BPA had to give formal Notice of Insufficiency telling preference customers it no longer will be able to meet their full requirements (their load growth after 1983). The 116 preference customers served by BPA are in a situation where they don't know what portion of their requirements in the future will be met from Federal resources. Prolonged uncertainty over the substance and mechanics of a long-term policy for allocation of the Federal resource affects the capability of utilities to provide for that portion of their forecasted requirements that cannot be met by the Federal system. Investor-owned utilities in the region are also affected by the uncertainty about what future requirements will be imposed on them. These uncertainties depend on whether or not new public agency preference customers are formed and whether or not the investor-owned utilities will receive applications for service from Federal agencies and direct-service industries after their contracts with BPA expire.

There are few alternatives open to the region for resolving the uncertainty about its future power supply. Regional power legislation (S. 885 and H.R. 6677) has been introduced by Northwest congressional representatives. This legislation would bring about an early resolution of the Federal energy allocation problem as well as resolving other pressing issues--the need for conservation and renewable resources, public participation in power planning, continued service to the region's important direct-service industries, and certain rate and financing matters.

With or without passage of regional energy legislation, some opportunity for increased coordination efforts among the utilities in the region will still exist. These efforts would bring about not only increased benefits to the region as a whole, but also to the individual utilities participating in the coordination effort.

Four specific areas have been identified for which some potential benefit might be realized through further coordination. These include (1) thermal coordination, (2) expanded geographic area generation and transmission planning, (3) additional interregional interties, and (4) United States-Canadian transactions. Because the latter three identified areas are regional opportunities, they are discussed in Chapter 9. For thermal coordination, a discussion of the present situation, the apparent opportunities for further coordination, the possible problems associated with bringing about this greater level of coordination, and the current status of the coordination effort follows.

THERMAL COORDINATION

Present Situation

At present 20 percent of the total system firm energy capability of NWPP member and associated utilities consists of thermal generators. This percentage will increase substantially over the next 10 years, reaching 50 percent during the 1990's. Coordination of the operation of these thermal resources will be necessary in order to integrate them efficiently into the existing hydroelectric based Northwest system. Although the Pacific Northwest Coordination Agreement and the Intercompany Pool arrangement presently provide some means for coordinating the planned maintenance and moment-by-moment operation of thermal generators, Pacific Northwest utilities recognize the need for improved means of achieving such coordination.

Opportunities and Impediments

Pacific Northwest utilities recognize that an appropriate, carefully balanced agreement among owners, operators, and participants in intermediate and baseload thermal generating units could achieve a number of benefits. These benefits include (1) spreading of the impact of thermal outages, scheduled and unscheduled, among the owners and participants in thermal plants; (2) providing the most economic thermal resources operation; and (3) protecting the regional adequacy and reliability of the combined hydroelectric and thermal system.

The proposed Thermal Coordination Agreement may result in the establishment of a central staff to perform some of the functions of a centralized dispatch center for thermal plants covered by that agreement.

BPA operates small percentage shares of generation at non-Federal Columbia River hydroelectric projects within its generation control area under "Service and Exchange Agreements," which provide the participant-owner of the resource with calculated

energy and capacity deliveries in exchange for delivering the variable output of the resource to BPA. BPA will offer these arrangements to other participant-owners of these and other hydroelectric projects. BPA may offer to provide services to new, large, baseload thermal plants in the future. The offer would include certain services related to the operation, management, and delivery of the output from the plants. These services could include transmission of project output, scheduling of project generation, forced outage reserves backup, advance delivery of energy, and energy storage.

There are, however, several impediments to early implementation of a thermal coordination agreement. Although there are financial advantages to be gained by power utilities when using the hydroelectric system to assist the thermal plants to shape their generation to load, the limit of such use needs to be defined and agreed upon before a thermal coordination agreement can be implemented. Flood control rule curves, outflow requirements, recreational requirements, curtailments by regulatory agencies, and navigational, ecological, and economically based requirements on the Northwest river systems all influence the flexibility with which the hydropower system may respond to the needs of a large thermal power pool. There is a very large amount of diversity in the type of thermal resources used by the various utilities that would become involved in a thermal coordination agreement. These resources include intermediate and baseload coal-fired plants, nuclear plants, combustion turbines, and some older oil-fired plants. Some diversities are caused by private, public, and Federal ownership of generating resources, as well as considerations with regard to regional preference legal mandates such as Public Law 88-552. Although the above mentioned diversities do not prohibit coordination of thermal generation, they do require that the terms of any agreement be carefully structured to maintain each utility's interests.

Status

Following preliminary task force investigations, the Pacific Northwest Utilities Conference Committee has formed a Hydrothermal Coordination Group as an ad hoc committee of the System Planning Committee. This group consists of representatives of the Bonneville Power Administration, Pacific Power & Light, The Montana Power Company, Seattle City Light, the Washington Water Power Company, Puget Sound Power & Light Company, Chelan County PUD No. 1, Washington Public Power Supply System, the Northwest Power Pool, and PNUCC itself. Purposes of the group are the following:

- Outline the contents of a thermal coordination agreement
- Identify issues for negotiation along with alternatives

- o Determine the interrelationship of thermal and hydroelectric resources in the NWPP, including potential pumped storage projects
- o Determine agreement participants and the geographical extent of the agreement
- o Obtain form and scope of an agreement
- o Obtain utility commitments for participation in development and negotiation of a thermal agreement

The Hydro-Thermal Coordination Group developed a set of guidelines devoted to the issues of participation, type of plants to be coordinated, fueling and maintenance outage scheduling, benefit sharing, pooling of replacement energy, interaction with hydroelectric systems including pumped storage, scheduling, coordinated instantaneous operation, data acquisition, reporting, and accounting. In March 1980 a workgroup was established to test the appropriateness and applicability of the guidelines by applying them to several specific examples. This analysis is currently underway.

CHAPTER 4
COORDINATION IN THE ROCKY MOUNTAIN POWER AREA

INTRODUCTION

The Rocky Mountain Power Area is strictly defined as that geographical area which comprises all of Colorado and parts of Wyoming, Nebraska, and South Dakota as shown in Figure 1. However, two of the coordinating groups that operate in the Rocky Mountain Power Area include member systems whose service territories extend into Utah, Montana, Arizona, and New Mexico. Hence, when considering utility system coordination, the Rocky Mountain Power Area overlaps portions of the Northwest Power Area and the Arizona-New Mexico Power Area.

The Rocky Mountain Power Area is split geographically, east and west, by the Rocky Mountains. Much of the generation is located at great distances from major load centers, and the Rocky Mountains impose physical limits on the location of transmission lines that connect these remote resources to the load. The area has a favorable generation mix of thermal (about 56 percent) and hydroelectric (about 33 percent) as given in Table 1. Utilities in the Rocky Mountain Power Area with more than 200 MW of installed capacity are listed in Table 8.

Three power pools--the Inland Power Pool, the Colorado Power Pool, and the Rocky Mountain Power Pool (RMPP)--operate in the area. The Inland Power Pool and the Colorado Power Pool are formal pools; the Rocky Mountain Power Pool is an informal, noncontractual organization. Table 9 shows the participation of Rocky Mountain utilities and agencies in these three power pools.

ROCKY MOUNTAIN POWER POOL

AREA DESCRIPTION--GENERATION AND LOADS

The RMPP encompasses the interconnected bulk power system in Colorado, Wyoming, and portions of Montana, Utah, Nebraska, and South Dakota as shown in Figure 11.

The peakload of the Rocky Mountain Area (a subarea of WSCC) during 1979 was 4847 MW in August, and the 1979 energy requirement

was 27,718 GWh.[1] Generation in the area at the end of 1979 was as follows:

Type	Amount (MW)	Percent of Total
Hydroelectric	2,070	32
Hydroelectric pumped storage*	162	3
Steam (coal)	2,904	45
Steam (gas or oil)	374	6
Nuclear	200	3
Combustion turbine	667	10
Internal combustion	53	1
Total	6,430	

*Pumped storage is normally 324. One unit had runner failure in June 1979 and will not be returned to service until February 1981.

SOURCE: WSCC loads and resource data.

The vast majority of the area in which the RMPP operates is sparsely populated with large distances between load centers. In addition, the area is on the eastern edge of the WSCC system with basically no transmission support from eastern systems due to the permanent opening of the east-west ties in 1974 because of operating problems.

The area of the pool is extremely rich in fossil fuel resources that are presently being developed at minemouth generating stations. Several utilities that are members of the RMPP are also members of the Northwest Power Pool (NWPP). These utilities include The Montana Power Company, Pacific Power & Light Company, and Utah Power & Light Company, all of which have resources and transmission commitments both inside and outside of the Rocky Mountain Power Area.

DEVELOPMENT OF COORDINATION

Coordination in the area now encompassed by the RMPP began when many small utilities formed the region's major investor-owned companies through merger, acquisition, etc. In the 1930's and 1940's, the U.S. Bureau of Reclamation constructed various irrigation projects in Colorado and Wyoming. These projects interconnected Federal system hydrogeneration with the existing

[1]Does not include the loads and generation of Utah Power & Light Company and The Montana Power Company, which are reported with Northwest Power Pool, but are also members of the RMPP.

TABLE 8--Rocky Mountain Power Area Generating Utilities[1]

Utilities with 200 MW or More Installed Capacity	Installed Capacity 1979 (MW)	Peakload 1979 (MW)
Colorado Springs, City of	357	307
Colorado-Ute Electric Association	425	434
Public Service Co. of Colorado	2,956	2,475
Tri-State G&T Association	441	946
Water and Power Resources Service (LM Region)	516	385
Water and Power Resources Service (UCRSP)	1,500	968
Black Hills Power & Light Co.	237	186

[1]Excludes three other utilities with generating capacities less than 200 MW. Does not include Utah Power & Light Company, Pacific Power & Light Company, nor The Montana Power Company, which are reported with the Northwest Power Pool, but are also members of RMPP.
SOURCE: FPC Forms 1 and 12.

systems in the area, and produced an integrated power system. The real impetus to coordination occurred during the mid-1950's when the Colorado-Wyoming area was connected to the Northwest Power Area and certain common operating problems were experienced that could not be addressed by any one entity.

POOL MEMBERSHIP

RMPP membership consists of seven investor-owned utilities; two rural electric generation and transmission cooperatives (REA's), two municipal systems, two Western Area Power Administration (WAPA) regions, and the Water and Power Resources Service. Members are the following:

- Public Service Company of Colorado
- Pacific Power & Light Company (Wyoming Division)
- The Montana Power Company
- Utah Power & Light Company
- Southern Colorado Power Division--Central Telephone & Utility Corp.
- Black Hills Power & Light Company
- Cheyenne Light, Fuel & Power Company
- Tri-State Generation & Transmission Association, Inc.
- Colorado-Ute Electric Association, Inc.
- City of Colorado Springs

TABLE 9--Participation of Utilities and Agencies in Coordinating Groups in the Rocky Mountain Power Area, as of June 1980

Utility or Agency	Common Abbreviation	Power Pool		
		Rocky Mountain Power Pool	Colorado Power Pool	Inland Power Pool
Investor-owned Utilities				
Public Service Company of Colorado	PSC	X	X	X
Pacific Power & Light Company (Wyoming Division)	PPL	X		
The Montana Power Company	MPC	X		
Utah Power & Light Company	UPLC	X		
Southern Colorado Power Division-Central Telephone & Utility Corp.	SCPC	X	X	
Black Hills Power & Light Company	BHPL	X		
Cheyenne Light, Fuel & Power Company	CHLF	X		
Public Service Company of New Mexico	PNM			X
Tucson Electric Power Company	TEP			X
El Paso Electric Company	EPE			X
Public Agencies				
Tri-State Generation & Transmission Association, Inc.	TSGT	X		X
Colorado-Ute Electric Association, Inc.	CUEA	X		X
City of Colorado Springs	CCS	X	X	X
Nebraska Public Power District	NPPD	X		
Salt River Project	SRP			X
Platte River Power Authority	PRPA	X		X
Basin Electric Power Cooperative	BEPC			X
Lamar Utilities Board	COL		X	
Plains Electric Generation and Transmission Cooperative, Inc.	PEGT			X
Wyoming Municipal Power Agency	WMPA			X
Federal Agencies				
Western Area Power Administration, Lower Missouri Region	WALM	X		X
Western Area Power Administration, Upper Colorado Region	WAUC	X		X
Water and Power Resources Service	WPRS	X		

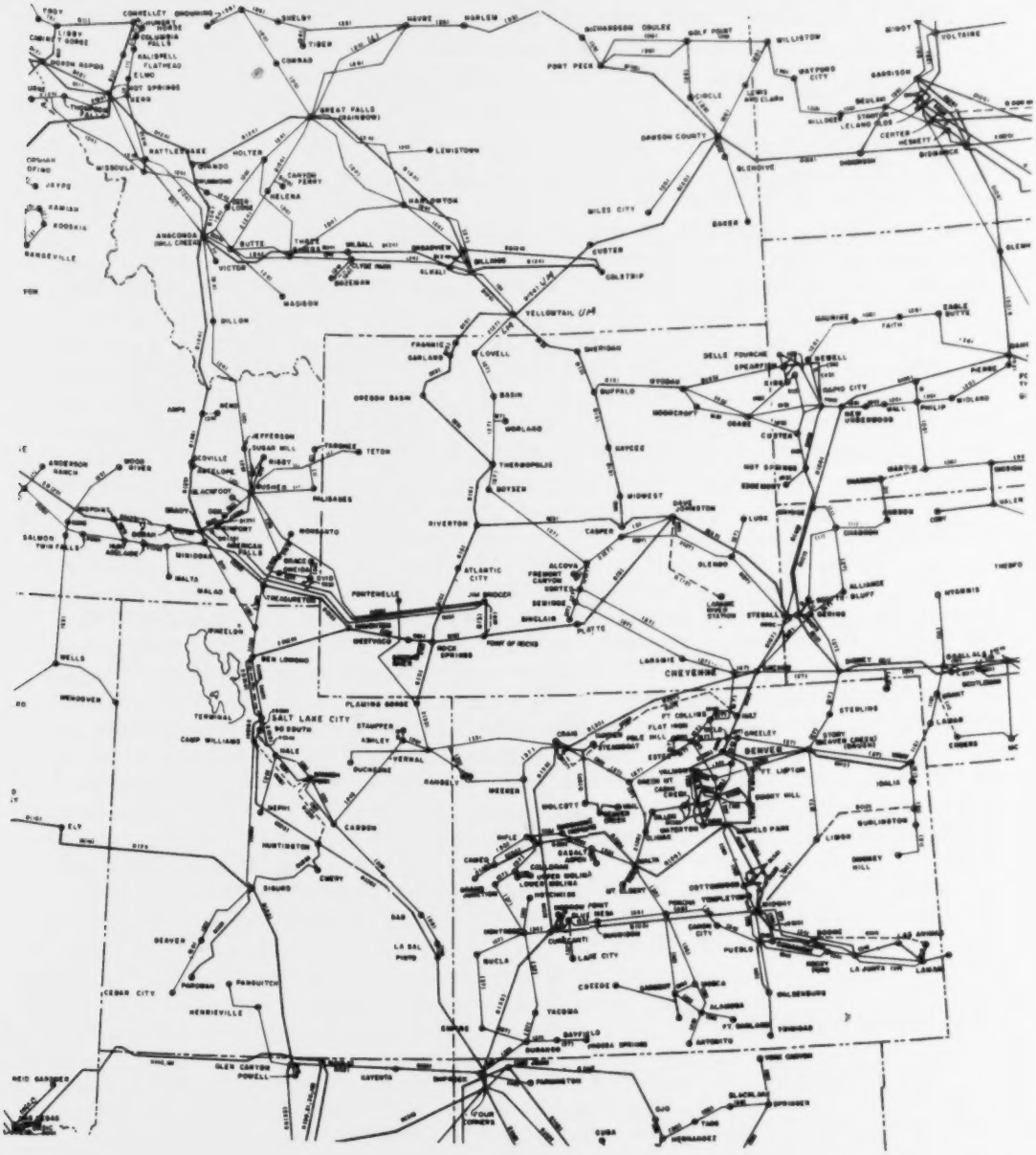

FIGURE 11--Rocky Mountain Power Pool Map

- Platte River Power Authority
- Western Area Power Administration-Lower Missouri Region
- Western Area Power Administration-Upper Colorado Region
- Water and Power Resources Service

POOL OPERATIONS

Operating guides for member systems are provided by either the Operations Committee, work groups, or ad hoc committees. The coordination of generation maintenance schedules, underfrequency load shedding, relaying, and scheduled outages of key transmission circuits through a designated center are also provided by these groups. Additionally, RMPP has adopted the NERC Operating Committee (formerly NAPSIC) guides, and various Western Systems Coordinating Council (WSCC) criteria as part of its operation.

RMPP is a leader in the coordination of activities across the broad scope of utility ownership. This success is due mainly to input from member systems. No change in pool organization other than new members is contemplated at this time.

REGULATION

The Rocky Mountain Power Pool Systems, being of diverse ownership, are subject to different degrees of regulation depending on structure of ownership and State in which they operate. All investor-owned utilities are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Security and Exchange Commission, and a State public utilities commission or equivalent. Municipal Systems are subject to regulation by a State public utilities commission for service provided outside of their corporate boundaries. All REA's are regulated by the public utility commission (PUC) in Colorado, Wyoming, and Utah. There is no regulation of REA's in Montana. Tri-State is not subject to Colorado PUC regulation because it serves in three States. Wholesale electric rates set by the Federal Systems (WAPA) are subject to approval by FERC.

TRANSMISSION EVALUATION

The transmission systems over the majority of the area are well designed and capable of meeting the local load requirements of the member systems during normal conditions. However, due to various reasons, portions of the system cannot always be operated within the WSCC minimum reliability criteria. That is, from time to time, the systems are unable to handle a single contingency loss-of-transmission line without an uncontrolled separation or cascading outage.

The principal reasons for this condition are the delays of major generating units in the area and associated transmissions that have been planned for integration of these new resources with existing systems. Four major areas of concern in the Rocky Mountain Power Pool Area with regard to significant transmission and reliability problems follow with a brief description of the problem areas and actions planned to correct the situation.

Eastern Colorado, Southern Wyoming, and Western Nebraska

Eastern Colorado, southern Wyoming and western Nebraska areas have been vulnerable to major transmission disturbances over the past several years. This problem is primarily caused by a shortage of generation within the area and by limited transmission to support the area during contingency situations. Generation additions have been in the planning process; however, as elsewhere, implementation has been delayed (in some cases, several years past the original commercial date) for various reasons. Generating units and associated transmission lines that have been delayed include the WPRS Mount Elbert Pump-Storage Units (200 MW), the PSCo Pawnee Unit (500 MW), and the Craig Units 1 & 2 (800 MW). In addition, the continuing delay of commercial operation at full capacity of the PSCo Fort St. Vrain Nuclear unit (330 MW currently limited to 200 MW) has required imports to cover its loss of firm power.

The delays of the above resources have necessitated importing considerable power to meet firm requirements. These imports, from time to time coupled with imports to cover forced outages, have exceeded the transmission capability into the area. Several times in the past few years the transmission system has been operated outside the minimum reliability criteria to avoid the dropping of firm customer loads. Several of the disturbances in this area, including some initiated by disturbances elsewhere on the WSCC system, have caused this system to become unstable because of the overload conditions.

Procedures have been adopted by all area utilities to implement a four-step process to reduce loads for the maintenance of a minimum level of reliability. The steps include internal company load reduction, the dropping of interruptable loads, appeal to the public, and the dropping of firm loads on a rotating basis.

As the new generating resources are completed and placed online, the stressing of the transmission system should be relieved. The completion of the Craig-Ault 345-kV line this past year was a significant improvement in the area's transmission system. Additionally, the completion of the Laramie River Station and associated transmission will have a significant impact in improving the area's reliability. The Laramie River Station near Wheatland, Wyoming, includes two 500-MW units on the west side of the east-west ties, and one 500-MW unit on the east side. The project includes 345-kV and 230-kV transmission into northern Colorado and western Nebraska. The first unit is scheduled for commercial operation by the summer of 1980.

Development of Coal-fired Generation in Wyoming and Montana

In the past few years, several major coal-fired generating units have been constructed in Wyoming and Montana near the abundant supply of low-sulfur coal. A large portion of the power generated at these sites serves firm loads in the Pacific Northwest Area. Transmission systems to deliver this power to the northwest loads have been subject to regulatory and construction delays. At this point, more generating capability is available in the Wyoming-Montana part of the RMPP area than transmission capability to export the power. Examples include the Jim Bridger Unit 4 (500 MW), which initially rolled during August 1979 with commercial operation by the end of 1979. However, due to delays in the construction of a 500-kV line between southern Idaho and Oregon, designed as part of the Jim Bridger Unit 4 Project, the full output of the Pacific Power & Light generation in Wyoming cannot be delivered to the northwest loads.

Another example is the inadvertent power flows on The Montana Power Co. (MPCo) system west of Billings, caused by coal-fired generation in Wyoming that is scheduled to the Northwest. These inadvertent flows have required the curtailment of MPCo's Colstrip generating station to stay within stability limits. The problem has posed such economic penalties on the Colstrip participants that interconnections between Billings and Yellowtail, Montana (161 kV and 230 kV) have been opened to eliminate the inadvertent flows overloading the Montana system. This action results in reducing the overall reliability of the interconnected systems. Both of the above examples will be corrected with the completion of planned additional EHV (500 kV) transmission lines between the coal-fired plants and the Northwest. Until the lines are constructed, however, the excess generation in this area will not be fully utilized. It is also essential that future coal-fired generating stations in this area be provided with sufficient transmission to meet the WSCC minimum reliability criteria and to mitigate the secondary impact of inadvertent flows on other WSCC systems.

Transmission Limitation Between the RMPP Area and Arizona-New Mexico System

Transmission capacity between the Rocky Mountain Power Area and the Arizona-New Mexico Power Area is deficient and in need of upgrading. Considerable economy transactions have been and are continuing to be made between these systems. In past years, these lines, which constitute a cross-section of the WSCC major loop, have been used extensively for economy transactions from the RMPP area to the Southwest. Also, coal-fired firm power in northern Colorado is transmitted over the Western Area Power Administration's system to Arizona. This transfer occurs during off peak hours when generation

from Glen Canyon is not available for exchange with northern Colorado thermal generation. With additional transmission capability between these areas, considerable additional economy transactions could be made using off peak coal-fired generation in the RMPP area to replace oil-fired generation in the Southwest. Utilities in the Southwest and RMPP areas are studying the addition of more transmission lines to increase the transfer capability and reliability.

Effect of Loop Flows on the RMPP Area

The WSCC network has been plagued with inadvertent power flows since the initial interconnections, especially with the completion of the Pacific Northwest-Pacific Southwest EHV interties and the EHV interconnections across the eastern side of the WSCC system. The system can be represented as a large loop with equivalent impedance. What this means is that power scheduled between two points on the system will actually flow in both directions following the impedance of the parallel paths. The power that flows in the opposite direction of the schedule is inadvertent power flow and is called "loop flow." When the Pacific Northwest has scheduled surplus hydroenergy to the RMPP area in the past few years, the predominate loop flow has been counterclockwise, causing considerable problems to the PNW-PSW participants. Economy schedules of surplus hydroelectric power had to be curtailed to stay within the stability limits of the transmission system. Recently, however, the loop flow has been predominately clockwise. One of the reasons for this change is the large thermal generation base in the RMPP area that is scheduled to meet firm loads in the Northwest. Thus, a component of each schedule actually flows south around the WSCC loop. Recent loop flows in the 300-600 MW range measured between the RMPP area and the Arizona-New Mexico systems have been common. The increasing clockwise loop flows are now and will continue to adversely affect the transmission system in the southern part of the RMPP area and the ability to export economy coal-fired energy to replace southwest oil-fired energy.

No practical solution to this problem exists. The official WSCC position on loop flow is accommodation with adjustment of economy schedules as necessary to control the loop flows. However, as the growth of RMPP Area coal-fired generation increases to serve firm northwest loads, the clockwise loop flow problem will continue to increase. Possible solutions include the opening of tie lines and the installation of phase shifting transformers. However, none of these solutions appears appropriate at present from an interconnected standpoint.

INLAND POWER POOL

AREA DESCRIPTION--GENERATION AND LOADS

The Inland Power Pool is a formal operating pool with the principal objective of sharing reserve capacity among its members. Members of the Inland Power Pool operate electric generation and transmission systems in Arizona, Colorado, New Mexico, Wyoming, and portions of Utah and Nebraska. The systems are interconnected by 345-kV, 230-kV, 138-kV, and 115-kV transmission lines.

Existing generating capability operated by members of the Inland Power Pool consisted of the following at the end of 1979.

Type	Amount (MW)	Percent of Total
Hydroelectric	2,152	18
Hydroelectric pumped storage	299	3
Steam (coal)	6,055	52
Steam (gas or oil)	1,538	13
Nuclear	200	2
Combustion turbine	1,183	10
Combined cycle	300	3
Internal combustion	16	0
Total	11,743	100

The coincident pool peak of 7133 MW occurred on September 4, 1979. Energy required by members in 1979 for firmload was 38,440,165 MWh.

HISTORY

During the early 1960's with the advent of the joint development of the Hayden Power Plant by the Colorado-Ute Electric Association, Inc. (Colorado-Ute) and the Salt River Project, and of the Colorado River Storage Project (CRSP) transmission system, numerous contractual arrangements were entered into among the private and public utilities and the Federal power agencies in Colorado and Arizona. Among these arrangements were provisions for the exchange of power and energy between CRSP and Salt River Project via a hydroelectric-thermal resource displacement arrangement. Under this arrangement, thermal power generated by Salt River Project at Hayden was delivered to CRSP for delivery to its northern area customers, while hydroelectric power generated at Glen Canyon was delivered to Salt River Project, avoiding the necessity for heavy transmission

lines from Glen Canyon to the northern area. A similar arrangement was made with Colorado-Ute where thermal power generated by Colorado-Ute at Hayden was delivered to CRSP while hydroelectric generation at the Curecanti Project was delivered to Colorado-Ute in western Colorado.

The contractual arrangements between CRSP and other parties provided for mutual assistance on an if, as, and when available basis. This arrangement was satisfactory for a number of years because CRSP had not marketed all of its hydroelectric capacity to firm customers. In the early 1970's this surplus capacity was allocated to firm customers and other arrangements were needed.

The development of the Yampa Project with four participants and the interconnected transmission needed to serve all participants provided an additional incentive to formalize an agreement for pooling of reserve capacity. Otherwise, each party would have to provide all of the reserves needed to cover individual hazards, and this was neither efficient nor economic.

In May 1974, the U.S. Bureau of Reclamation (currently Water and Power Resources Service), Colorado-Ute, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission Associates, Inc., and Salt River Project formed the Inland Power Pool and consolidated provisions for coordinated operations into one contract. Significant savings resulted from the pooling of operating reserve capacity.

AREA CHARACTERISTICS INFLUENCING POOLING

Several characteristics of the Inland Power Pool Area affect pooling. The most favorable area characteristic is the mix of thermal (79 percent) and hydroelectric (21 percent) resources. This fairly large proportion of hydroelectric resources provides a good source of potential peaking power and reserve capacity, limited, however, by the availability of transmission capacity to transmit such power where it is needed. Most of the favorable hydroelectric sites have already been developed, but it is expected that coal-fired generation will continue to develop, increasing the proportion of thermal resources relative to the hydroelectric resources over time.

Another favorable area characteristic is the diversity in peaking characteristics of the various member utilities. Most of the members operate summer peaking systems, but one member system, Colorado-Ute Electric Association, Inc., operates a winter peaking system. This enables Colorado-Ute to provide additional support during the summer to the other members and to receive support from such members in the winter. Also, even among summer peaking systems, there is diversity in the time of peaks, which provides further flexibility and opportunities for economy transactions.

Some of the most serious unfavorable area characteristics are geographical. The Inland Power Pool area is split geographically,

east and west, by the Rocky Mountains. This imposes physical limits on the location of transmission lines connecting the pool members. Furthermore, much of the newer generation in the area is located a long distance from the major load centers of Denver, Colorado Springs, and Pueblo in Colorado; Cheyenne, Wyoming; Albuquerque, New Mexico; and Phoenix and Tucson in Arizona. Especially in the areas of eastern Colorado, southern Wyoming, western Nebraska, and between Colorado and Arizona-New Mexico, the ability to pool resources is severely limited by the lack of sufficient transmission capacity.

The ability to construct new transmission lines when needed is hindered somewhat by the large amounts of Federal and Indian lands in the Inland Power Pool area. Federal laws and regulations applicable to these lands create delays and additional costs whenever they must be crossed.

In addition, the prevention of significant deterioration and visibility protection provisions of the Federal Clean Air Act may prohibit construction of new major coal-fired plants in large areas within the Inland Power Pool. Stringent implementation of these provisions could prevent construction of new generation even in major load growth areas, further complicating the transmission problems.

TRANSMISSION SYSTEM EVALUATION

To date, the transmission systems of the Inland Power Pool members have been adequate to meet the requirements of the agreement. However, several transmission problem areas exist that limit the participants' ability to support each other during emergency situations. The two major problem areas to the Inland Power Pool members are (1) the eastern Colorado, southern Wyoming, and western Nebraska areas; and (2) the transmission limitation between the Colorado and Arizona-New Mexico systems.

Because of the significance of the transmission problem to the Inland Power Pool members, the following summaries of each problem area and planned transmission additions that will relieve the problem are presented.

Eastern Colorado, southern Wyoming, and western Nebraska have experienced major disturbances over the past several years. These disturbances primarily are due to a shortage of generation within the area, and to limited transmission to support the area during contingency situations. Generating units and associated transmission lines that have been delayed include the WPRS Mount Elbert Pump-Storage Units (200 MW), the PSCo Pawnee Unit (500 MW), and the Craig Units 1 and 2 (800 MW). The continuing delay of full power output of the PSCo Fort St. Vrain Nuclear Unit (330 MW) has required imports to cover the expected availability of firm power from this unit.

The delays of the above resources have required power imports to meet firm requirements. These imports, coupled with emergency

imports due to forced outages of generating units, have, from time to time, exceeded the transmission capability into the area. Several times in the past few years the transmission system has been operated below the minimum reliability criteria to avoid the dropping of firm customer loads.

As the new generating resources are completed and placed in service, stress on the transmission system should be relieved. The completion of the Craig-Ault 345-kV line significantly improved the area's transmission system. The completion of the Laramie River Station and associated transmission will have a significant impact on this area. The Laramie River Station near Wheatland, Wyoming, includes two 500-MW units on the west side of the east-west ties and one 500-MW unit on the east side. The project will add significant amounts of new 345-kV and 230-kV transmission into northern Colorado and western Nebraska. The first unit is scheduled for commercial operation by summer 1980.

Transmission capacity between the Rocky Mountain Power Area and the Arizona-New Mexico Power Area is deficient and in need of upgrading. Transactions have been and are continuing to be made between these systems. With additional transmission capability between these areas, additional economy transactions could be made using off-peak coal-fired generation in the area to replace oil- or gas-fired generation in the Arizona-New Mexico area. Utilities in Arizona, New Mexico, and Colorado are studying the addition of more transmission lines to increase transfer capacity and reliability.

POOL DESCRIPTION

Pool Membership

The charter members of the Inland Power Pool are the Public Service Company of Colorado, Salt River Project, Colorado-Ute Electric Association, Inc., Platte River Power Authority, Tri-State Generation and Transmission Association, and the Western Area Power Administration (Upper Colorado and Lower Missouri Regions). Additional participants are the City of Colorado Springs, Basin Electric Power Cooperative, Tucson Electric Power Company, Public Service Company of New Mexico, Wyoming Municipal Power Agency, Plains Electric Generation and Transmission Cooperative, and El Paso Electric Company.

Other electrically interconnected utilities with one or more parties that will not add to the operating reserve quota or to the responsibility to provide replacement capacity may become members of the Inland Power Pool.

Arizona Public Service Company, Intermountain Consumer Power Association, and the City of Farmington have expressed interest in becoming members but have not yet been admitted.

Organization Structure

Administration of the Inland Power Pool activities is controlled by the Operating Committee, which establishes the working practices of the pool. Each member utility appoints one representative to the Operating Committee. One of the member systems, selected by the Operating Committee as pool coordinator, serves as a collection agent and clearinghouse for pool operating data. Presently, the Public Service Company of Colorado is serving as pool coordinator. The Operating Committee must meet once a year, but in practice has met more frequently to deal with operating matters.

Pooling Interactions Between Members of Different Ownership

The Inland Power Pool is composed of member utilities from Federal, investor-owned, cooperative, and municipally owned systems. The members operate in differing jurisdictional areas and are subject to a diverse mix of State and Federal regulatory authorities.

Despite the wide diversity among members regarding type of ownership and applicable regulatory authorities, the common interest in pooling reserves provides a strong unifying force. All of the pool members share an interest in developing economic, efficient, and reliable service to their customers.

COORDINATION ACTIVITIES

Coordination of Planning

Each year the Operating Committee assembles and reviews the members' forecast annual peakloads and resources for a 10-year period. These projections are used to compute the operating, spinning, ready, and replacement reserve obligations for the pool and for each member in the future years. These projections assist the members in planning future resources and measuring the impact of such resources on reserves. This tool is also used to evaluate the impact of utilities who desire to join the Inland Power Pool.

The Inland Power Pool Agreement recognizes the prudence of planning to meet a 1 day in 10 year loss-of-load probability. The agreement also states the intent of members to meet or exceed the WSCC Minimum Operating Reliability Criteria.

No other formal planning requirements are mandated in the Inland Power Pool Agreement but members are involved in numerous ad hoc study and planning groups that deal with development in certain areas served by pool members. An example is the joint effort of the Public Service Company of Colorado and the Colorado-Ute Electric Association to extend the 230-kV transmission network for the Wolcott-Basalt-Malta area in north central Colorado down to an

interconnection with New Mexico utilities in the south central Colorado Area. The Colorado-New Mexico interconnection is a joint effort of the Public Service Company of Colorado, Colorado-Ute Electric Association, the Public Service Company of New Mexico, and Plains Electric Generation and Transmission Cooperative. Another example is a joint study effort of the transmission system now under way between Utah Power & Light, WAPA, and Colorado-Ute Electric Association to provide for joint development of the EHV transmission in the Utah-Western Colorado Area.

These informal, task-oriented working groups have thus far served the parties well as a way to jointly study and develop bulk power generation and transmission facilities. The need for a formal contractual relationship between the various parties to define the planning coordination responsibility has not developed to date, and the lack of such a formal relationship has not hindered joint efforts. The flexibility provided by using task-oriented groups has been very valuable. However, the systems in the Inland Power Pool area are presently reviewing the need to expand pool functions beyond the sharing of reserves. A special task force meeting was held in Denver on October 19, 1979, to begin development of a coordinated planning agreement. Subsequent to the October 19 meeting, both the Operations Committee and an ad hoc Planning Committee have developed principles for an expanded Inland Pool. These have been accepted by the members and each has appointed official negotiators to develop a formal agreement for the expansion of the operating functions and to include a planning function. A more formal effort may be valuable in the future as pool membership expands and additional areas of mutual benefit and interest can be defined.

Coordination of Operations

Operation Committee Functions--The Operating Committee of the Inland Power Pool coordinates the reserve sharing activities of the pool members along with related matters as directed by the Inland Power Pool Agreements. The meetings of the Operating Committee also serve as a forum for discussing the entire range of operating problems and opportunities experienced by the members. Because there are numerous two- and three-party agreements, and multiparty agreements existing between the various members, the extent of coordination of operations between the members is greater than the Inland Power Pool Agreement alone would indicate. An example is the energy interchange provisions in the two-party contracts between WAPA and various pool members. Using interchange, the hydroelectric operations and thermal plant operations can be coordinated to the mutual advantage of each party.

The Operating Committee is charged with developing operations agreements to define methods, practices, and procedures to implement provisions of the pool agreement. Six operating agreements have

been approved by the Operating Committee and development continues on others.

Operating Reserve Capacity--The principal feature of the Inland Power Pool Agreement is the shared obligation of the parties to provide operating reserve capacity for the pool. The parties schedule a total amount of operating reserve each hour that is equal to or greater than the larger of (1) 7 percent of the pool load carried by thermal resources plus 5 percent of the pool load carried by hydroelectric resources, or (2) the largest single pool contingency plus 1 percent of the combined pool load.

Operating reserve consists of spinning reserve and ready reserve. The spinning reserve component of operating reserve ranges from 50 to 75 percent depending on the hydrothermal generation mix during any hour. The balance of operating reserve may be either ready reserve or additional spinning reserve. Ready reserve is capacity capable of becoming spinning reserve within 10 minutes.

The obligation of each party to provide spinning reserve and operating reserve is based on their reserve responsibility ratio. The following formula is used for each month to compute a ratio:

1. Monthly Load (0.25) + (1.0) (Largest Thermal Unit), or
2. Monthly Load (0.25) + (0.71) (Largest Hydroelectric Unit),

whichever is larger for any party. The resulting numbers are summed, then each number is divided by the sum to give a ratio called the reserve responsibility ratio. Monthly load for this calculation is the highest load on a party's system in the preceding 12-month period.

Each party has an operating reserve quota equal to the greater of:

1. Seven percent of the party's load carried by thermal resources plus 5 percent of the party's load carried by hydroelectric resources, or
2. The pool operating reserve capacity requirement times the party's reserve responsibility ratio.

No party is required to provide more operating reserve than its own largest single contingency loss plus 1 percent of its own load.

Replacement Capacity--The parties will provide replacement capacity so that the sum of replacement capacity and operating reserve capacity is equal to or greater than the sum of the first and second largest possible contingency losses of the pool. Replacement capacity must be available in 10 hours.

Settlements for Reserve--Each party reports the actual capacity and load conditions for each hour to the pool coordinator, who calculates the obligations for each party and the deviations. At

the end of each month statements are prepared for settlements between parties with excess reserve and those deficient in reserve.

Emergency Assistance--Any party will supply emergency assistance to a requesting party as needed to protect or restore service to firm customers, subject to availability and potential impairment of firm power service in a member's own system. There is no demand charge for emergency assistance. Energy is returned to the supplying party at 1-1/2 times the amount received, and there is a limit of 10 consecutive days for such assistance. Beyond 10 days a party must arrange for scheduled outage assistance.

Scheduled Outage Assistance--Scheduled outage assistance is mutually agreed to between the receiving and supplying parties. A demand charge of $45 per megawatt per day is provided for. Energy is returned to the supplying party at a 1 to 1 rate between non-Federal parties, but a 1-1/2 to 1 rate was insisted upon by the United States.

REGULATION

Because the various Inland Power Pool members serve within differing jurisdictional areas, and are of varying ownership types, there are variations in the regulatory authorities applicable to each member. It would take many pages to discuss completely all of the variations. No such attempt will be made here.

Instead, the following lists of typical regulatory authorities are presented.

Regulation of Rates and Financial Matters

Regulation of rates and financial matters generally is as follows, depending on ownership of the member systems.

1. Investor-owned Systems
   - -Federal Energy Regulatory Commission
   - -Securities and Exchange Commission
   - -State Public Utilities Commission
2. Generation and Transmission Cooperatives
   - -Federal Energy Regulatory Commission
   - -Rural Electrification Administration
   - -State Public Utilities Commission
3. Federal Systems
   - -Federal Energy Regulatory Commission
4. Municipal Systems
   - -Federal Energy Regulatory Commission
   - -Municipal Authorities

-State Public Utilities Commission (outside municipal boundaries)

5. Salt River Project
   - -Federal Energy Regulatory Commission
   - -Board of Directors

Regulation of Construction and Operation of Facilities

Inland Power Pool member systems are, in general, subject to the same Federal laws and regulations governing the construction and operation of facilities, while also being subject to various State laws and regulations. In many cases, similar regulation is imposed by more than one level of government.

The web of Federal, State, and local rules and regulations applicable to Inland Power Pool members results in a large number of permits and aprovals that must be obtained before a new facility can be constructed and operated.

As an example of the magnitude of the regulation and permit process that exists now, Basin Electric Power Cooperative has needed 57 permits issued by 20 agencies to construct the Laramie River Station in Wyoming. Colorado-Ute Electric Association has needed 58 permits for Craig Station Units 1 and 2, and will need numerous additional permits for Unit 3.

Typical regulatory authorities include the following:

1. Federal level
   - -Environmental Protection Agency
   - -U.S. Army Corps of Engineers
   - -Department of Agriculture
     - --Rural Electrification Administration
     - --Forest Service
   - -Department of Energy
     - --Federal Energy Regulatory Commission
     - --Economic Regulatory Administration
   - -Department of Interior
     - --BLM
     - --Indian Affairs
     - --Fish and Wildlife Service
   - -Federal Aviation Administration
2. State level
   - -Public Utilities Commission
   - -Land Use Commission
   - -Air Pollution Control Division
   - -Water Quality Control Division
   - -State Engineer
   - -Water Courts (State District Court)

Names used here are applicable to Colorado. Each State has similar agencies, although there may be more or fewer agencies having different functions in other States.

3. Local level
   -Planning and Zoning Commissions
   -Board of County Commissioners

EVALUATION OF CURRENT POOLING

The economics of pooled reserve capacity is the principal benefit enjoyed by members of the Inland Power Pool. Larger, more efficient units can be built in the area, and the total amount of installed capacity is less than it need be if members operate in isolation. Savings are realized by operating less reserve on an hourly basis.

The Inland Power Pool Agreement provides the contractual framework for emergency assistance, scheduled outage assistance, and the collection of operating data to ensure reserves are available to the pool. The Operating Committee has provided a forum for discussing and resolving operating problems. The mix of ownerships with a common goal has served to eliminate artificial barriers between member systems.

Some autonomy may seem to be lost when individual resources are pooled for the common good; but this disadvantage, if it is one, is offset many times by the benefits derived by members of the pool.

COLORADO POWER POOL

AREA DESCRIPTION--GENERATION AND LOADS

The Colorado Power Pool encompasses the Colorado area served by its member systems. The pool's 1979 peakload was 3065 MW (occurring in August); and the pool's 1979 energy requirement was 15,320,772 MWh.

Pool resources consisted of the following generation at the end of 1979.

Type	Amount (MW)	Percent of Total
Hydroelectric	46	1
Hydroelectric pumped storage	150	4
Thermal	2,785	80
Nuclear	200	6
Combustion turbine	262	8
Internal combustion	25	1
Total	3,468	100

The transmission system within the pool consists of multiple 115- and 230-kV lines that interconnect member systems (including internal 44-, 69-, 115-, and 230-kV transmission lines). Although many of these lines would qualify as jointly owned, in reality they are segmentally owned. Each system owns the portion within its service territory.

The reliability of the pool system is more than adequate. However, the pool is subject to WSCC disturbances that often isolate Colorado and southeast Wyoming from the interconnected Western System. These disturbances seldom cause a separation within the Colorado Power Pool, but frequency swings, load shedding, etc., are experienced.

DEVELOPMENT OF COORDINATION

The formation of the Colorado Power Pool in the mid-1950's was occasioned by the interconnection of the Public Service Company of Colorado (Public Service) with both the city of Colorado Springs and the Southern Colorado Power Division of the Central Telephone and Utilities Corporation. These interconnections were covered by separate agreements between Public Service and each member system. The formal pool agreement provided for reserve sharing, reserve requirements, and coordinated operation with Public Service designated as pool dispatcher. Although the pool agreement did not include a formal planning function, subsequent enhancement to the interconnected system has been jointly planned and often jointly constructed. In 1972, the pool was expanded to include the City of Lamar.

POOL MEMBERSHIP

Membership consists of two investor-owned systems[2] and two municipal systems[3]. The municipal systems are regulated by the Colorado Public Utilities Commission (PUC) to the extent that they serve loads outside their corporate boundaries. Both of the investor utilities are under the jurisdiction of the Colorado PUC and FERC as applicable.

Most thermal units owned by member systems are capable of burning at least two fuels (gas and oil or gas and coal), and fuel availability has not been a problem. Except during emergencies, older units are often restricted to burning fuel to meet air pollution requirements. Major generation, however, is coal-fired, and each member has long-term fuel supply contracts.

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[2]Public Service Company of Colorado and Southern Colorado Power Division of Central Telephone and Utilities Corporation.

[3]Colorado Springs and the City of Lamar.

BENEFITS

Benefits derived from the pool include the following:

- o Coordinated operation of the pool systems
- o Inclusion of the three other systems in the Public Service Control Area
- o Municipal systems' access to lowered Federal hydroelectric power through the Public Service system
- o Sharing of reserves
- o Emergency assistance
- o Joint use of transmission facilities

AREA OUTLOOK

The member systems of the Inland Power Pool are presently drafting a formal agreement to expand the Inland Power Pool with respect to the operating function and to include a planning function. Presently there is little impetus for pool changes in the Colorado Power Pool. Southern Colorado Power is making no generation addition and has become a wholesale customer of Public Service. Both Colorado Springs and Public Service are members of the Inland Pool, which probably will be the vehicle for increased pooling in the area.

CHAPTER 5
COORDINATION IN THE ARIZONA-NEW MEXICO POWER AREA

INTRODUCTION

The Arizona-New Mexico Power Area includes, in general, all of Arizona, most of New Mexico, and a portion of West Texas, as shown in Figure 1.

The major load centers are located in the population centers of south central and southern Arizona and north central New Mexico. The area has a high percentage of coal-fired steam capacity (over 52 percent), most of which is located near large coal reserves in the Four Corners area. Gas- and oil-fired steam, combined cycle, and internal-combustion capacity account for most of the remaining generating resources (41 percent). The hydroelectric resources, which amount to only 6 percent, are along the Colorado River. The area is characterized by long distances between load and generation sources and an extremely high summer peak due to irrigation pumping and air conditioning loads.

The coordinating groups described in this chapter are the following:

- New Mexico Power Pool
- Arizona-Nevada Power Pool
- Arizona Public Service-Salt River Project (APS-SRP) Power Pool
- Lower Colorado River Power Pool
- Arizona Power Pooling Association
- Salt River Project-Puget Agreement
- Western Energy Supply and Transmission Associates (WEST)
- Agreement on Principles of Interconnected System Operations (for jointly owned Arizona-New Mexico and Nevada Projects)
- Arizona Public Service Company-Tucson Electric Power Company (APS-TEP) Power Pool
- Arizona Public Service Company-Utah Power & Light Company (APS-UP&L) Interconnection Agreement
- Arizona Public Service Company-Nevada Power Company (APS-NPC) Power Coordination Agreement
- Southwest Area Transmission Planning Committee (SWAT)
- Cactus Power Pool

Generating utilities in the Arizona-New Mexico Power Area with more than 200 MW of installed capacity are listed in Table 10.

TABLE 10--Arizona-New Mexico Power Area Generating Utilities[1]

Utilities with 200 MW or More Installed Capacity	Installed Capacity 1978 (MW)	Peakload 1978 (MW)
Arizona Electric Power Cooperative	393	199
Arizona Public Service Company	4,214	2,435
Water and Power Resources Service (LC Region)	525	--
Imperial Irrigation District	391	340
Salt River Project	2,447	2,196
Tucson Electric Power Co.	864	838
Public Service Company of New Mexico	871	683
El Paso Electric Company	1,091	690

[1]Excludes nine other utilities with generating capacities less than 200 MW.
SOURCE: FPC Forms 1 and 12.

Table 11 shows utility and agency membership in the several coordinating organizations and agreements in effect in the area.

NEW MEXICO POWER POOL

DEVELOPMENT OF COORDINATION

The New Mexico Power Pool (NMPP) stems from an interconnection agreement of five utilities that was signed in 1956. The relationships between the parties involved were later supplemented by informal agreements, by two- and three-party agreements, and by multiparty agreements. The multiparty agreements also involved utilties outside New Mexico--e.g., Principles of Interconnected System Operations (Four Corners, Palo Verde). Although the original contract is concerned only with sharing Federal transmission facilities with non-Federal utilities, the term "New Mexico Power Pool" is used here to refer to the overall power pooling effort.

POOL DESCRIPTION

The NMPP is an operating pool consisting of five systems that span most of New Mexico and extend southward into Texas (Figure 12). Member systems include the Western Area Power Administration, Upper Colorado Region, (WAUC)--formerly administered by the U.S. Bureau of Reclamation (USBR)--the Community Public Service New Mexico Company (CPA), the El Paso Electric Company (EPE), the Plains Electric Generation and Transmission Cooperative, Inc. (PGT),

TABLE 11--Participation of Utilities and Agencies in Various Organizations and Agreements in the Arizona-New Mexico Power Area

Utility or Agency	Common Abbreviation	New Mexico Power Pool	Arizona-Nevada Power Pool	Arizona Public Service-Salt River Project Power Pool	Lower Colorado River Power Pool	Arizona Power Pooling Association
Investor-owned Utilities						
Arizona Public Service Company	APS			X	X	
Community Public Service Company	CPS	X				
El Paso Electric Company	EPE	X				
Nevada Power Company	NEVP		X			
Public Service Company of New Mexico	PNM	X				
Puget Sound Power & Light Company	PSPL					
San Diego Gas & Electric Co.	SDGE					
Southern California Edison Company	SCE				X	
Tucson Electric Power Company	TEP					
Utah Power & Light Company	UPLC					
Public Agencies						
Arizona Electric Power Cooperative, Inc.						X
Electrical District No. 2 of Pinal County						X
Imperial Irrigation District	IID				X	
Los Angeles Department of Water & Power	LDWP					
Mesa, City of						X
Plains Electric Generation and Transmission Cooperative, Inc.	PGT	X				
Salt River Project Agricultural Improvement & Power District	SRP		X	X		
Federal Agencies						
Western Area Power Administration, Upper Colorado	WAUC	X				
Lower Colorado	WALC		X			
Water and Power Resources Service Lower Colorado Region	WPRS					

TABLE 11--Participation of Utilities and Agencies in Various Organizations and Agreements in the Arizona-New Mexico Power Area (Continued)

Utility or Agency	Salt River Project-Puget Agreement	Western Energy Supply & Transmission Associates	Arizona Public Service Co.-Tucson Electric Power Co. Power Pool	Arizona Public Service Co.-Utah Power & Light Co. Interconnection Agreement	Arizona Public Service Co.-Nevada Power Co. Power Coordination Agreement	Southwest Area Transmission Planning Committee	The Principles of Interconnected Systems Operation
Investor-owned Utilities							
Arizona Public Service Company		X	X	X	X	X	X
Community Public Service Company							
El Paso Electric Company		X				X	X
Nevada Power Company		X			X		X
Public Service Company of New Mexico		X				X	X
Puget Sound Power & Light Company	X						
San Diego Gas & Electric Co.						X	
Southern California Edison Company		X				X	X
Tucson Electric Power Company		X	X			X	X
Utah Power & Light Company				X			
Public Agencies							
Arizona Electric Power Cooperative, Inc.						X	
Electrical District No. 2 of Pinal County							
Imperial Irrigation District							
Los Angeles Department of Water & Power		X					X
Mesa, City of							
Plains Electric Generation and Transmission Cooperative, Inc.							
Salt River Project Agricultural Improvement & Power District	X	X				X	X
Federal Agencies							
Western Area Power Administration, Upper Colorado		X					
Lower Colorado						X	X
Water and Power Resources Service Lower Colorado Region		X				X	X

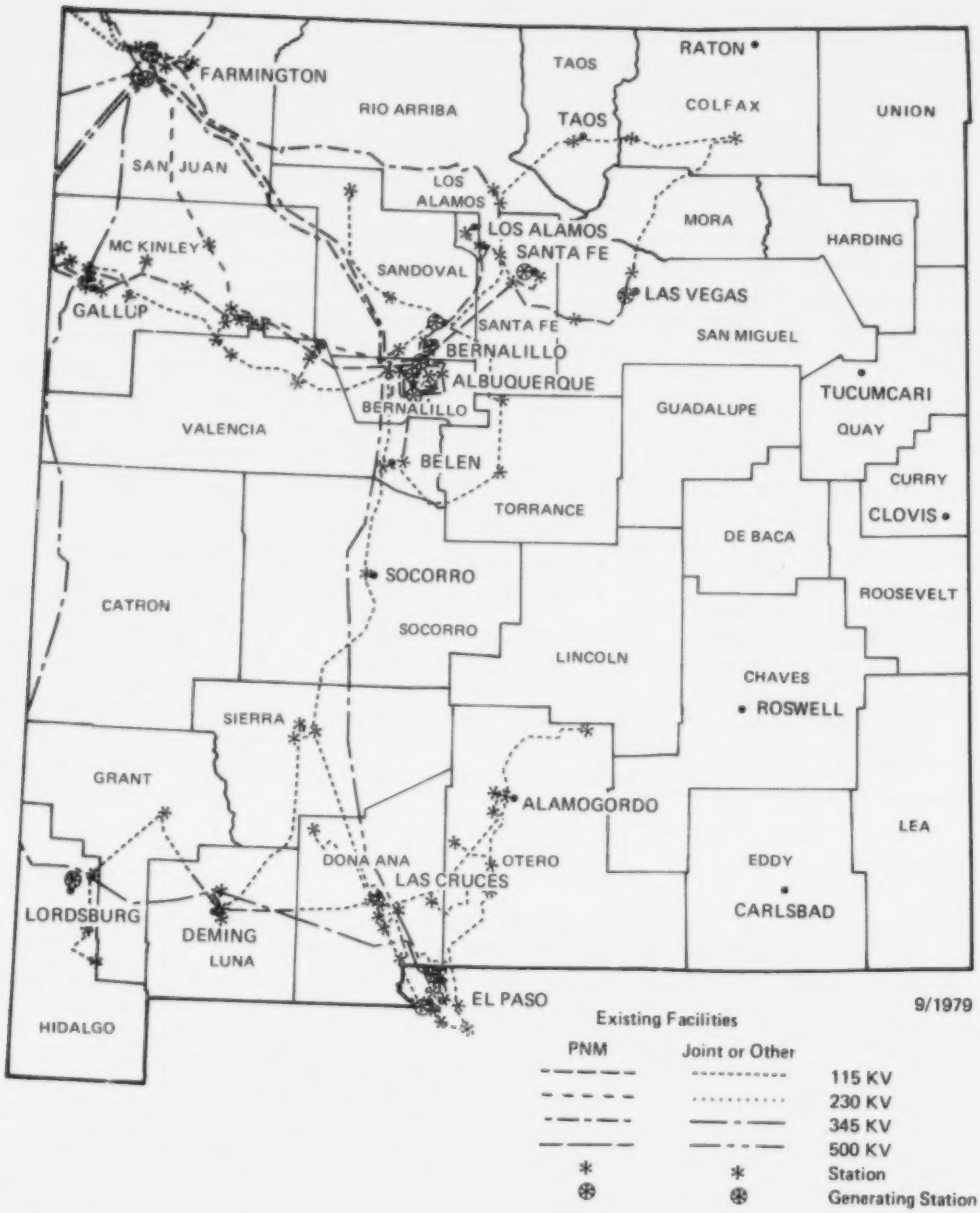

FIGURE 12--Major Interconnected Transmission Systems in New Mexico

and the Public Service Company of New Mexico (PNM). The pool was organized in 1956, and the current roster of NMPP members still consists of the original five systems. Annual peak pool load occurs during the summer. Generation facility sources are primarily thermal--coal-fired and gas- and oil-fired steam. WAUC and PGT have sizeable hydroelectric imports. Information concerning 1980 NMPP projected loads, resources, and reserves are shown in the following table.

Joint-use generation and transmission line ownerships within the NMPP are not uniform. Joint-use generating units are all jointly owned. Generation planning within the NMPP is coordinated, but joint-use transmission line ownership, on the other hand, is quite varied. The four major categories of ownership arrangements are: (1) wheeling--single ownership, (2) trade of capacity--single ownership, (3) joint divided interest, and (4) joint undivided interest.

Resource	Megawatts
Hydroelectric	24
Steam-Coal	870
Steam-Gas and Oil	1,009
Combustion Turbine	93
Combined Cycle	224
Net Purchased Capacity	165
Total Resources	2,385
NMPP 1980 Projected Load	1,935
Reserve Margin	450

REGULATION

According to the terms of the NMPP Agreement, annual evaluations of the NMPP transmission grid are required. Computer runs on all major transmission lines are prepared yearly for 5 and 10 years into the future, and potential overloads and other operating problems can be detected early. Although the pool cannot require a member utility to add or replace any equipment, it can make the member aware of the potential problem and recommend a solution.

Reliability of NMPP transmission and generating facilities is maintained through the NMPP Agreement, separate two-party agreements, the Inland Power Pool, and the Principles of Interconnected Operations (Four Corners). These agreements formalize additional agreements regarding emergency support, spinning reserve, and installed reserve capacity. Along with local and State regulation of non-Federal utilities, FERC also has jurisdiction over two- and multiparty agreements.

PLANNING

The pool itself has no control center and no staff--therefore, no real-time operational control functions are performed. For the past few years, at the request of the Operating Committee, PNM has been coordinating the spinning reserve requirements among the members.

The NMPP is composed of the Operations, Engineering, and Executive Committees. The Operations Committee meets quarterly to discuss such matters as maintenance schedules, load trends, new facilities, communications, and operating procedures. The Engineering Committee meets annually to examine load projections for the next 5 years and to prepare power flow studies. The Executive Committee meets annually to discuss such topics as the Engineering Committee Report, the Operations Committee Report, and the need to install additional transmission facilities to provide adequate services to NMPP customers.

The NMPP agreement requires each member to maintain a spinning reserve capacity in proportion to its load, so that the total of pool spinning reserves will at least be equal to the pool's largest single hazard. Each member must meet its daily spinning reserve requirement at its peak hour or make arrangements with others to provide the required amount of spinning reserve for its use.

Future transmission line construction plans are routinely submitted to the Engineering Committee and included in the committee's power flow studies. The power flow studies are useful tools for pool members and help eliminate duplication of transmission lines. Special transmission line studies are also numerous. In the past, two or three member utilities have pooled their funds to build transmission lines, but these projects are the result of two- and three-party agreements--not a direct result of the NMPP.

BENEFITS

Several advantages are involved with NMPP membership. Sharing transmission facilities and use of coordinated planning, for example, are definite advantages. Individual members also gain an accurate perspective of the status of the NMPP transmission grid and can more accurately make their own plans. One disadvantage, however, is the lack of a uniform mechanism for sharing installed reserve.

ARIZONA-NEVADA POWER POOL

COMPOSITION

The parties to the Arizona-Nevada Power Pool Agreement are the United States (Parker-Davis Project), the Nevada Power Company, and

the Salt River Project (SRP) Agricultural Improvement and Power District. The Parker-Davis Project, originally authorized May 28, 1954, included the consolidation of the Parker Dam Power Project and the Davis Dam Power Project (built on the lower Colorado River by the Bureau of Reclamation). The project's purpose was to generate and transmit power and energy on market areas in southern Nevada, southern California, and Arizona. Today, the Parker-Davis Project has been consolidated with the Boulder Canyon Project (Hoover) and the Navajo Project under WAPA to market and transmit Federal electric power and energy.

The Nevada Power Company, an investor-owned utility, includes the service territories of Clark and Nye Counties in southern Nevada. (See Figure 13.) The Nevada Power Company provides electric service to approximately 162,000 residential, commercial, and other customers.

The SRP is a political subdivision of Arizona. SRP provides electric service to residential, commercial, industrial, and agricultural power users in a 2900-square-mile service territory in parts of Maricopa, Gila, and Pinal Counties. (See Figure 14.)

Table 12 indicates the resource capacity by type of power, and 1978 peakloads for Arizona-Nevada Power Pool members.

REGULATION

Because the Nevada Power Company is an investor-owned utility and the SRP is a political subdivision of Arizona, the regulatory authority varies for the pool members. The Nevada Power Company is regulated by the Public Service Commission of Nevada and by FERC. SRP is regulated by its Board of Directors. The board members, who establish policies for management and the conduct of its business affairs, are elected by the landowners and power customers in the Salt River Project's service area.

SYSTEM OPERATIONS

The systems of the Nevada Power Company and the SRP are interconnected through the Parker-Davis Transmission System of the USBR. The parties that recognized the potential benefits of this interconnection signed the Arizona-Nevada Power Pool Agreement on June 1, 1971.

The Arizona-Nevada Power Pool Agreement allows the parties to put into effect arrangements for coordinated operation of the electric systems of the Nevada Power Company, the United States, and the Salt River Project for the purpose of achieving the following reciprocal services.

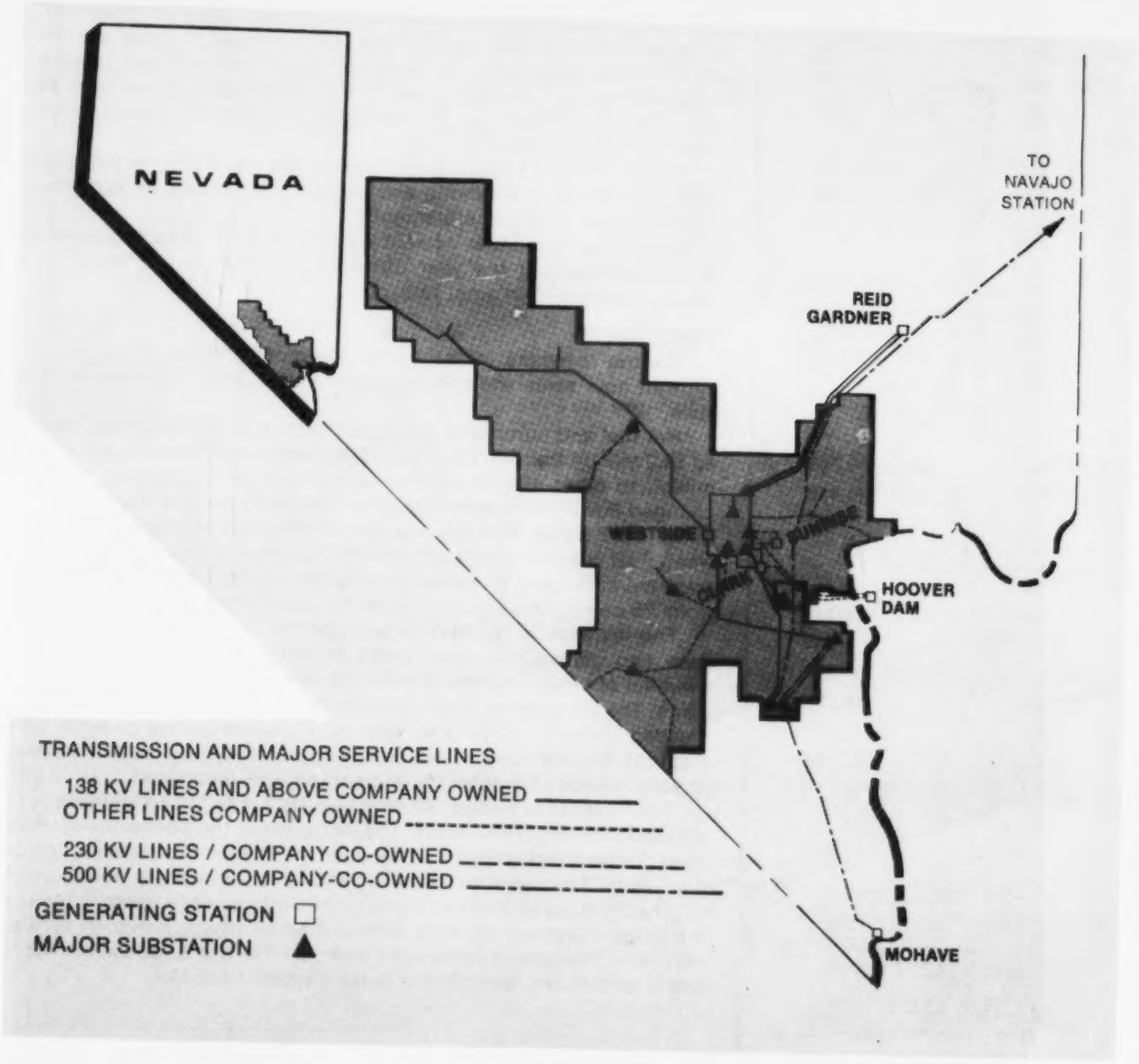

FIGURE 13--Nevada Power Company Area of Service,
December 31, 1978

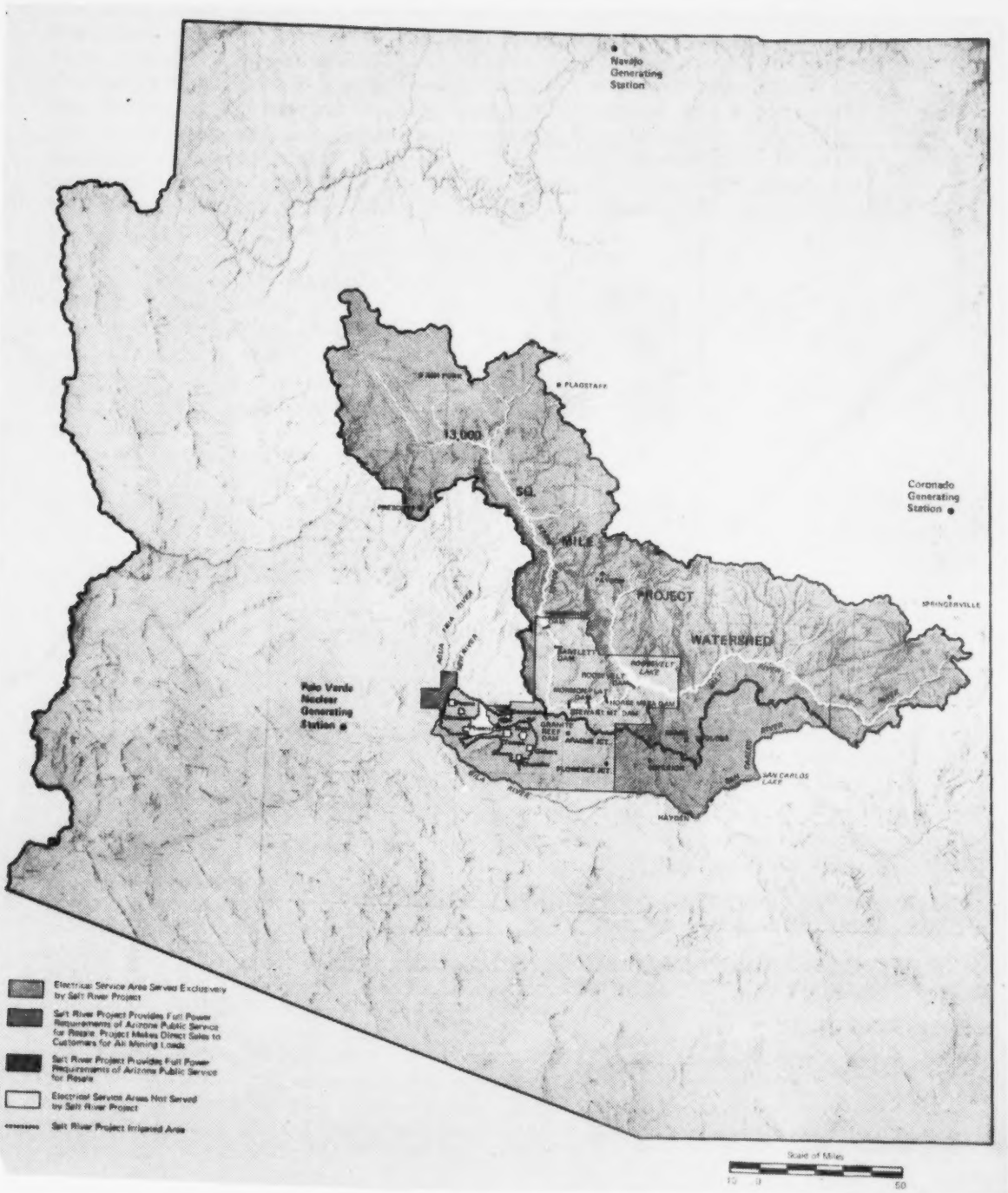
Navajo Generating Station
Coronado Generating Station
Palo Verde Nuclear Generating Station
PROJECT
WATERSHED
13,000
50
MILE
Electrical Service Area Served Exclusively by Salt River Project
Salt River Project Provides Full Power Requirements of Arizona Public Service for Resale. Project Makes Direct Sales to Customers for All Mining Loads
Salt River Project Provides Full Power Requirements of Arizona Public Service for Resale
Electrical Service Areas Not Served by Salt River Project
Salt River Project Irrigated Area
Scale of Miles
50

FIGURE 14--Salt River Project Service Area

TABLE 12--Arizona-Nev

Party	Total (MW)
Parker-Davis-Hoover (Boulder Canyon Project Navajo Project)[1]	2,252
Nevada Power Company	1,341
Salt River Project	2,468

[1]Represents United States portio

vada Power Pool Resource Capacity for 1978 by Generation Type

Hydro-electric (MW)	Steam-Coal (MW)	Steam-Oil/Gas (MW)	Combustion Turbine (MW)	Combined Cycle (MW)	Diesel (MW)	Peakload 1978
1,705	5,474	0	0	0	0	464
100	807	276	128	0	30	1,259
232	1,017	538	393	288	0	2,196

n of Navajo Project recovered in 1985.

Spinning Reserve Capacity--Provides for the interchange of spinning reserve capacity between the power systems of the parties. This type of interchange calls for the occasional operation by one party of more spinning reserve capacity (synchronized generating capacity in excess of load being carried) than would be called for by conditions in its own system in order to make up for a deficiency of such spinning reserve capacity being maintained at the time by the other party or parties, when such operation is in the interest of overall economy or overall reliability in the combined systems of the parties.

Emergency Assistance--Establishes terms and conditions for reciprocal assistance between the parties under emergency conditions. Any party will, upon request of another party, supply as emergency assistance such power as the requesting party may need in order to protect or restore service to its firm customers, subject to the availability of such power and subject to the condition that such supply will not result in impairment of, or serious jeopardy to, firm power service in the supplier's system. A party from whom emergency assistance is requested will, to the extent required, call upon all power sources available to it and will give such emergency assistance priority over interruptible or secondary deliveries to other parties.

In addition to the Arizona-Nevada Power Pool Agreement, the Salt River Project has entered into separate Energy Interchange Agreements with the Nevada Power Company and the Western Area Power Administration. The type of energy interchange primarily intended to be provided for is commonly known as economy interchange. Economy interchange can be supplied from power sources available at the time that would not otherwise be fully utilized but which can be used by the receiver to reduce generation from more expensive units, to avoid starting generating units not in active service, and to reduce or avoid curtailing deliveries of secondary or interruptible power.

OPERATING COMMITTEE

The Arizona-Nevada Power Pool Operating Committee consists of six representatives, two designated by each member. The members of the Arizona-Nevada Power Pool have established an Operating Committee as a means of securing effective cooperation in the planning of system development, and dealing in a prompt and orderly basis with various technical and operating problems that arise in connection with system coordination under changing conditions.

BENEFITS

The members believe that coordination through the Arizona-Nevada Power Pool Agreement and the energy interchange agreements yields

important benefits to their respective customers in Arizona, Nevada, and California. These benefits include the following:

1. The combined power loads of the members' electric systems have been supplied and protected with less aggregate spinning reserve capacity and with consequent net savings in expenses.
2. Emergency conditions have been met with less likelihood of curtailment or impairment of electric service to the customers.
3. The members have made more efficient and economical use of generating facilities and interconnections with other power systems.
4. Energy interchanges have allowed benefits through the reduction of generation from more expensive units, avoided starting generating units, avoided more expensive energy purchases, and avoided curtailing deliveries of secondary or interruptible power.

ARIZONA PUBLIC SERVICE COMPANY-SALT RIVER PROJECT POWER POOL

COMPOSITION

The Arizona Public Service-Salt River Project (APS-SRP) Power Pool is composed of the electrical system of the Arizona Public Service Company and the Salt River Project Agricultural Improvement and Power District. The pool services electric customers within Arizona.

The Arizona Public Service Company is an investor-owned utility in Arizona. The company's service territory includes all or part of 11 of Arizona's 14 counties. (Refer to Figure 15 for service territory.) Arizona Public Service provides electric service to approximately 348,000 residential, commercial, industrial, and other customers.

The Salt River Project is a political subdivision of Arizona. SRP provides electric service to residential, commercial, industrial, and agricultural power users in a 2900-square-mile service territory in parts of Maricopa, Gila, and Pinal Counties. (Refer to Figure 14 for service territory.)

The annual peakload for the pool occurs during the summer months. APS's peakload for 1978 was 2549 MW; SRP's peakload for the same year was 2196 MW. Following are resource capacities and types for the pool members in 1978.

System	Total	Hydroelectric	Steam-Coal	Steam-Oil Gas	Combustion Turbine	Combined Cycle
APS	2,795 MW	5 MW	1,478 MW	576 MW	511 MW	225 MW
SRP	2,468 MW	232 MW	1,017 MW	538 MW	393 MW	288 MW

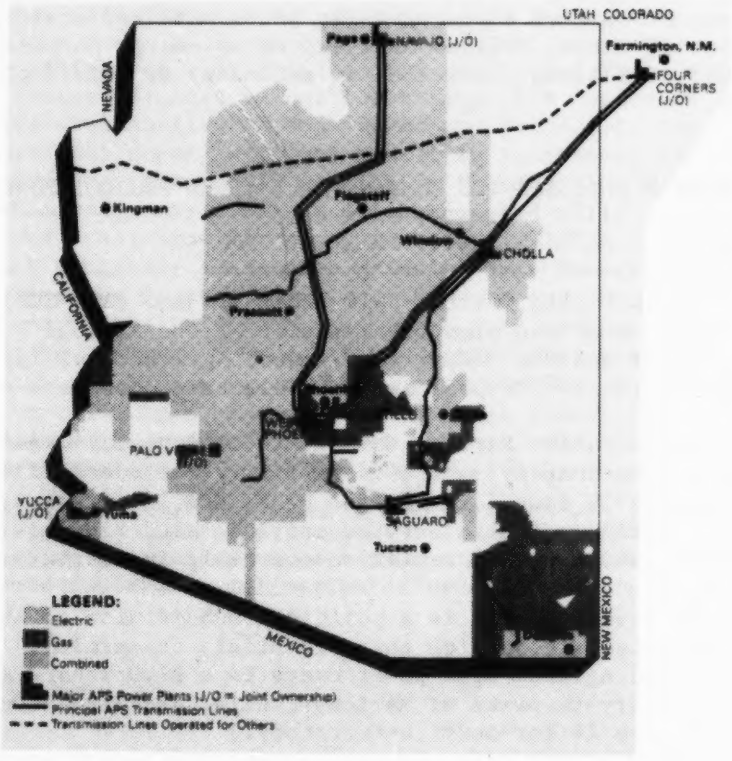

FIGURE 15--Arizona Public Service Company Area of Service

REGULATION

Because Arizona Public Service is an investor-owned utility, and the Salt River Project is a political subdivision of Arizona, regulatory authority for the pool members varies. Arizona Public Service is regulated by the Arizona Corporation Commission, FERC, and the Economic Regulatory Administration. The Salt River Project is regulated by its Board of Directors. The board members are elected by the landowners and power users in the Salt River Project's service area, and they establish policies for management and the conduct of its business affairs.

DEVELOPMENT OF COORDINATION

Before 1955, the electric systems of Arizona Public Service and the Salt River Project had long been interconnected at various points. These interconnections allowed for a substantial degree of coordination for the interchange of power and energy. Arizona Public Service and the Salt River Project had also established and maintained a high degree of coordination for purposes of improving the quality, reliability, and economy of electric service in the respective territories served.

On August 31, 1955, Arizona Public Service and the Salt River Project entered into an agreement to (1) clarify the respective service territories, thereby facilitating orderly and economical development and expansion of the facilities of each system, (2) cancel various existing agreements between Arizona Public Service and the Salt River Project that were no longer adequate and appropriate for operating and economic conditions, and (3) provide for a new agreement between Arizona Public Service and the Salt River Project for the interchange of power and energy, and for more extensive coordination in planning, operation, and development of the electric systems of Arizona Public Service and the Salt River Project.

POWER COORDINATION AGREEMENT

The Power Coordination Agreement was entered into on September 15, 1955 between the Arizona Public Service Company and the Salt River Project Agricultural Improvement and Power District. Although this agreement was not entitled a "pooling" agreement, it provided for all of the transactions included in most power pools.

The agreement initially provided for the coordination and development of the APS-SRP Pool through the construction of the following generating units for the purpose of sharing installed and operating reserves:

1. APS constructed two gas- and oil-fired generating units with nominal capacity of 100 MW each, located east of Phoenix.

2. SRP constructed two gas- and oil-fired generating units with nominal capacity of 100 MW each, located northwest of Phoenix.

Arizona Public Service and the Salt River Project regularly consult with each other and cooperate in planning the development of their joint systems.

SYSTEM OPERATIONS

The Power Coordination Agreement makes possible coordinated planning for operation of the pool to effectuate the following reciprocal services.

Energy Interchange--The type of energy interchange primarily intended to be provided for is commonly known as economy energy interchange, which can be supplied from power sources available at the time that they would not otherwise be fully utilized and which can be utilized by the receiver to reduce generation from more expensive units, to avoid starting generating units not in active service, to reduce or avoid more expensive energy purchases, and to avoid curtailing deliveries of secondary or interruptible power.

Spinning Reserve Interchange--The type of interchange intended to be provided for as spinning reserve interchange is the occasional operation by one party of more spinning reserve capacity (synchronized generating capacity in excess of load being carried) than would be called for by conditions in its own system in order to make up for a deficiency of such spinning reserve capacity being maintained at the time by the other party, when such operation is in the interest of overall economy or overall reliability in the combined systems of the parties.

Capacity Equalization--The purpose is to provide arrangements under which disparities (as between the parties) in margin of reserve capacity in each party's aggregate power resources over its aggregate power requirements will be compensated by power equalization charges and credits, and under which the party with relatively less margin of reserve capacity will be entitled to receive equalizing power from the other party.

Reciprocal Emergency Assistance--The purpose is to establish terms and conditions for reciprocal assistance between the parties under emergency conditions when power supply to consumers is threatened or curtailed in either system.

Transfer of Power to Fringe-Area Customers--The purpose is to establish arrangements for supply of electric power service to fringe-area customers of one party through transmission and distribution facilities of the other party. Fringe-area customer

means a customer of one party to which, by reason of distance or other circumstances, service would be difficult and expensive if supplied from existing service facilities of that party, but to which service can be supplied with less difficulty and expense from existing service facilities of the other party.

COORDINATION COMMITTEE

The Coordination Committee consists of two representatives, one designated by each party. The functions and responsibilities of the Coordination Committee include the following:

1. Establish general policies for coordination of the operation of the electric systems
2. Review the prospective power requirements of the two systems
3. Investigate with respect to time, nature, location, and ownership, additional generating facilities and related transmission facilities
4. Exercise general supervision and guidance over the Operating Committee
5. Consider and act upon matters referred to the Coordination Committee by the Operating Committee
6. Perform all other functions as directed by the APS-SRP Power Coordination Agreement

OPERATING COMMITTEE

The Operating Committee consists of four representatives, two designated by each party. The functions and responsibilities of the Operating Committee include the following:

1. Establish procedures and standard practices for the guidance of load dispatchers as to matters affecting interconnected operations
2. Establish procedures and standard practices as to determinations of costs and expenses and of energy losses in connection with energy interchanges and other intersystem transactions
3. Establish detailed metering arrangements required in connection with transactions
4. Perform all functions as directed by the APS-SRP Power Coordination Agreement

BENEFITS

Arizona Public Service and the Salt River Project believe that the coordinated planning, development, and operation of the APS-SRP Pool have yielded important benefits to electric service customers

and to the economic growth of the territories served. The coordinated efforts allow the pool to be supplied with adequate reserve capacity by less aggregate installed generating capacity with consequent net savings in investment and expenses. Emergency conditions in the APS-SRP Pool have been met with less likelihood of curtailment or impairment of electric service. Coordinated development has allowed the installation of generating facilities on an economical basis as to timing, unit size, location, and ownership. Generating facilities have been utilized to generate in a more efficient and economical manner. The planning efforts have allowed the development of transmission lines within the pool in a cost-effective manner. Energy interchanges have allowed benefits through the reduction of generation from more expensive units, avoided starting generating units, avoided more expensive energy purchases, and avoided curtailing deliveries of secondary or interruptible power. These and many more benefits have been realized by Arizona Public Service and the Salt River Project through the Power Coordination Agreement.

Transmission coordination under the terms of the 1955 Salt River Project and Arizona Public Service Company Power Coordination Agreement have yielded significant benefits. An example of these benefits is the $9 million that will be jointly saved by the two parties through the coordinated development of 230-kV transmission facilites that are required in the Phoenix metropolitan area during 1982-85. This savings results from the elimination of about 15 miles of line and a delay of construction of about 16 miles of line for about 2-7 years.

LOWER COLORADO RIVER POWER POOL

The parties involved in the Lower Colorado River Power Pool (LCRPP) are Arizona Public Service (APS), Southern California Edison (SCE), and the Imperial Irrigation District (IID).

The activities of the LCRPP are centered around the loads and resources of the parties located in the area along the Colorado River in southwestern Arizona and southeastern California. IID's loads are all located in this area, but the loads of APS and SCE in the LCRPP area are isolated from their main G&T systems. The area in which the LCRPP is located is shown on Figure 16 and it should be pointed out that the three main transmission lines into the area are owned and operated by the Western Area Power Administration (WAPA). Because the transmission into the area is mainly owned and operated by WAPA, APS, SCE, and IID have to continually coordinate with WAPA to ensure adequate transmission capacity into the area.

In the mid-1950's the local transmission systems of APS, SCE, and IID in the LCRPP area were becoming more interconnected. Also, load growth in the area was beginning to justify the addition of generation facilities. Because of the above factors and the recognition of the benefits of coordination of planning and

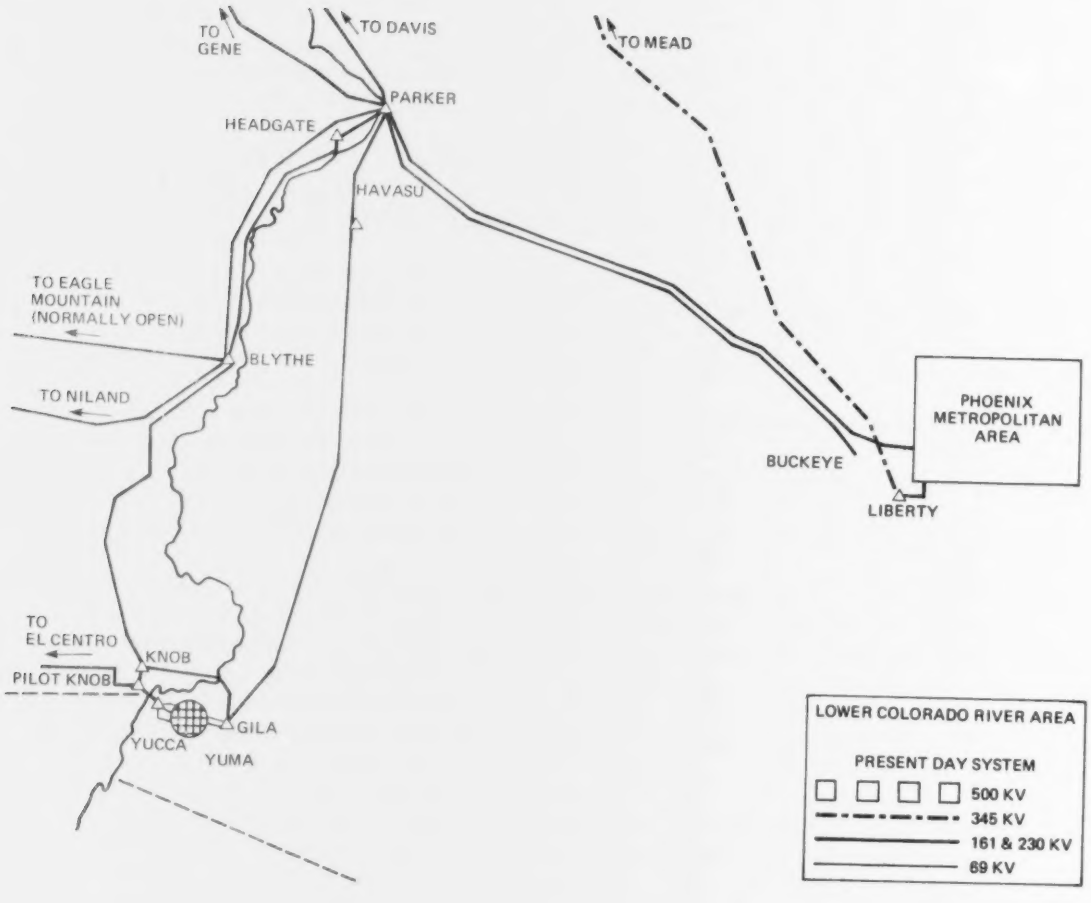

FIGURE 16--Lower Colorado River Area Transmission Network

operations, the parties entered into a Power Coordination Agreement and Participation Agreement #1, both of which are dated December 4, 1956. (Participation Agreement #1 was later superseded by Participation Agreement #2.) These two agreements provided the basis for the coordination and planning of loads and resources for and for the construction of a jointly owned 75-MW generating facility.

The organization of the LCRPP is as follows:

1. Coordination Committee--Establishes general policies for coordination of operation, periodically reviews the aggregate power requirements, arranges for investigation with respect to additional generating capacity, and exercises general supervision over the Operating Committee.
2. Operating Committee--Establishes rules and standard practices affecting interconnected operation, establishes detailed metering arrangements required for any transaction, and brings to the attention of the Coordination Committee any matters needing its attention.

The Power Coordination Agreement (PCA) provides for the following power pool functions, which help achieve economies in costs and improvement in reliability of the interconnected systems.

1. Economy Energy--Service Schedule A of the PCA provides for economy energy interchange to fully utilize the most economical generating units available to reduce generation from more expensive units, to avoid more expensive energy purchases, and to avoid curtailing deliveries of secondary or interruptible power.
2. Reciprocal Emergency Assistance, Reserve Capacity, and Spinning Reserve--Service Schedule B of the PCA establishes terms and conditions under which APS, SCE, and IID provide (a) reserve capacity (each party provides 25 MW), (b) spinning reserve (each party provides 25 MW), and (c) reciprocal emergency assistance. The agreement recognizes the transmission limitations to the Yuma area, and calculations are based on generation and loads in the area.
3. Capacity Participation--Service Schedule B of the PCA, in addition to 2 above, also provides policy by which the parties shall plan, build, own, and pay operating costs for any joint participation units in the Yuma area.

The following table indicates the amount and type of generating resource capacity in megawatts in the LCRPP area for APS, SCE, and IID in 1978.

Party	Steam Oil/Gas	Hydro-electric	Combustion Turbine	Diesel	Total (MW)
APS	25	--	157	--	182
SCE	25	--	--	--	25
IID	205	39	102	12	358

The following table indicates the 1978 peakloads for APS, SCE, and IID.

Party	Megawatts
APS	144
SCE	40
IID	340
Total	524

ARIZONA POWER POOLING ASSOCIATION

DESCRIPTION AND MEMBERSHIP

The Arizona Power Pooling Association is a voluntary nonprofit corporation. Its members are electrical utilities with service areas covering portions of Arizona including Cochise, Graham, Santa Cruz, Maricopa, Mohave, Pima, and Pinal Counties. The association's combined 1978 peakload was 340.6 MW; the 1978 net energy generated was 1,561,592.6 kWh. Association members are the following:

- City of Mesa (municipality) located in Maricopa County
- Electrical District Number Two of Pinal County (municipality), located near Casa Grande and other central Pinal County towns
- Arizona Electric Power Cooperative Inc.--a rural electric generating and transmission cooperative with five distribution cooperative members--(Mohave Electric, Mohave County; Trico Electric, Pima and Pinal Counties; Graham County Electric, Graham County; Sulphur Springs Valley Electric, Cochise and Santa Cruz Counties; and Duncan Valley Electric, Graham County)

The three systems have equal representation. Coordination is continuous and allows each member to maximize the benefits of available resources.

Generation

The association has hydroelectric contracts with the Western Area Power Administration (WAPA) for Parker-Davis Project Power and Energy, Hoover Power and Energy, and Colorado River Storage Project Power and Energy. Also, the Arizona Electric Power Cooperative has two 175-MW coal-fired units and 175-MW of oil, gas, and combustion turbine generation.

Transmission

The association uses member-owned transmission facilities of the WAPA Parker-Davis System, and other systems by which transmission is contractually provided.

Reliability

The self-generation and internal transmission of the association in 1978 was highly reliable because of mature generating units. Because of contractual interrelationships with other transmission and generation systems, the association can only give an internalized report.

Regulation

Pool members are regulated by their consumer-owners and by the REA, which oversees the Rural Electrification Cooperatives. The municipal and cooperative entities are not regulated by FERC. Cooperatives are regulated by the Arizona Corporation Commission, and the municipalities are regulated by the electoral process.

Development of Coordination

The Arizona Power Pooling Association was created in the late 1960's through the influence of the U.S. Bureau of Reclamation (now WAPA). Hydroelectric resources were low-load factor, and resources were limited in availability. As member systems' loads increased, the need and desire to integrate hydroelectricity with thermal-base generation became obvious. Power pooling allows maximization of operating benefits through scheduling of resources.

COORDINATION ACTIVITIES

Members meet monthly to discuss generation, transmission, scheduling, and planning. Members at the senior management level

also meet monthly to discuss contemporary problems and future planning. Developmental costs of the pool are shared, but individual activities are not (unless other members so desire to participate). All operations are coordinated through a single computerized dispatching center.

EVALUATION OF CURRENT POOLING

Benefits

Each member is able to maximize the benefit of its resources resulting in the lowest cost of power to the consumer-owners of these nonprofit cooperative and municipal entities.

Disadvantages

Presently, the only constraint is that members look first to each other to supply needs not otherwise met by contractual or other resources. The members do not regard this as a disadvantage.

Possible Changes

Increased internal staffing and the establishment of permanent committees is one possible organizational change. Regarding contract changes, members may decide to commit to joint generation.

Less Binding Coordination Groups and Pools

The association interacts with WAPA, the SRP, Tucson Electric Power Company, Arizona Public Service, Southern California Edison, Public Service of New Mexico, and other electrical systems with which contracts may be established.

SALT RIVER PROJECT-PUGET SOUND POWER & LIGHT CO. EXCHANGE AGREEMENT

Puget Sound Power & Light Company (Puget) and SRP signed an Exchange Agreement on October 16, 1974. SRP and Puget own and operate electrical systems that have diverse load and resource characteristics. These characteristics allow Puget and SRP to exchange capacity and energy, thus displacing energy generated from combustion turbines during the months of high system demand. SRP delivers power to Puget in November, December, January, and February; Puget delivers equal amounts of power to SRP in June, July, August, and September. Because SRP's and Puget's electric

systems are noncontiguous, the exchange of capacity and energy also involves Utah Power & Light Company, The Washington Water Power Company, and the United States as wheeling agents.

During the winter of 1974-75 and the summer of 1977, the Salt River Project and Puget exchanged 100 MW, made possible through seasonal load diversity. This transaction contributed to the displacement of combustion turbine capacity resulting in a fuel savings for SRP of approximately $2 million.

WESTERN ENERGY SUPPLY AND TRANSMISSION ASSOCIATES

Western Energy Supply and Transmission Associates (WEST) was created in 1964 by a group of 10 utilities to coordinate regional planning in nine western States. WEST itself does not generate or supply electric power, nor does it own or operate electric generating plants or transmission lines. It does, however, encourage coordinated planning of large generating units and extra-high-voltage (EHV) transmission lines, and conducts research of interest to its members. Today, WEST comprises 20 major electric utilities serving customers in all or part of 10 western States.

Several large generating stations are the result of planning by WEST members. Among those developed under the WEST concept are the Four Corners Plant, the Mohave Generating Station, the Navajo Generating Station, and the Palo Verde Nuclear Generating Station. These projects involved the efforts of the following eight members plus the WPRS at the Navajo Generating Station.

1. Arizona Public Service Company
2. El Paso Electric
3. Los Angeles Department of Water & Power
4. Nevada Power Company
5. Public Service Company of New Mexico
6. Southern California Edison Company
7. Salt River Project
8. Tucson Electric Power Company

The advantage of economy of scale is the principal benefit of coordinated planning of large generating units and EHV transmission lines under the auspices of WEST Associates. Benefits realized from participation in the Four Corners, Mohave, and Navajo projects have been estimated by the Salt River Project based on its total entitlement of 807 MW in those projects. The SRP's combined capital expenditure, including the associated transmission lines, was approximately $450 per kilowatt in 1979 dollars. If the Salt River Project had installed two 400-MW coal-fired units, the average cost in 1979 dollars would have been approximately $700 per kilowatt.

AGREEMENT ON PRINCIPLES OF INTERCONNECTED SYSTEM OPERATIONS
(for jointly owned Arizona-New Mexico and Nevada projects)

The construction of the Four Corners Units 4 and 5, Mohave Generating Station, and Navajo Generating Station resulted in the addition of extensive associated transmission facilities (shown in Figure 17). The transmission facilities allowed participants in the Four Corners, Mohave, and Navajo Projects to enter into energy interchange and reciprocal service agreements among themselves and other utilities. The addition of transmission facilities also prompted the participants to adopt the Agreement on Principles of Interconnected System Operations. These principles were later adopted by the Palo Verde Project participants.

The Agreement on Principles of Interconnected System Operations provides the terms and conditions for interconnected system operation that are appplicable as follows:

1. Forecast Capacity Resources Margin--It is prudent that each member provide a forecast capacity resources margin equal to at least 15 percent of the estimated peak demand for each month.
2. Spinning Reserve Capacity--Participants are obligated to maintain a minimum amount of spinning reserve capacity at all times.
3. Emergency Service
   a. Spinning reserve capacity (without energy).
   b. Capacity resources and associated energy that are scheduled and purchased by one participant from another to meet a part of the purchaser's electric system load requirements. If the purchaser shows a forecast margin of less than 15 percent, that participant will pay an emergency service fee plus a penalty fee.
4. Interruptible Load as a Substitute for Spinning Reserve Capacity--The amount of interruptible load that any participant uses for spinning reserve capacity cannot exceed 15 percent of that participant's obligation to maintain spinning reserve capacity.
5. System Operations--The participants operate their electric systems continuously in parallel; however, each participant has the right to separate the wholly owned facilities of its electric system from the electric system of any other participant(s).

The plant owners have formulated additional agreements on an as-needed basis. Examples are the Four Corners Unit Tripping Agreement (May 22, 1969) and the Six Party Economy Energy Agreement (November 15, 1974). Underfrequency load conservation is done on a coordinated, but informal, areawide basis.

Coordination of maintenance at any particular plant is accomplished through its Engineering and Operating Committees. However, an Advisory Committee consisting of all operating agents

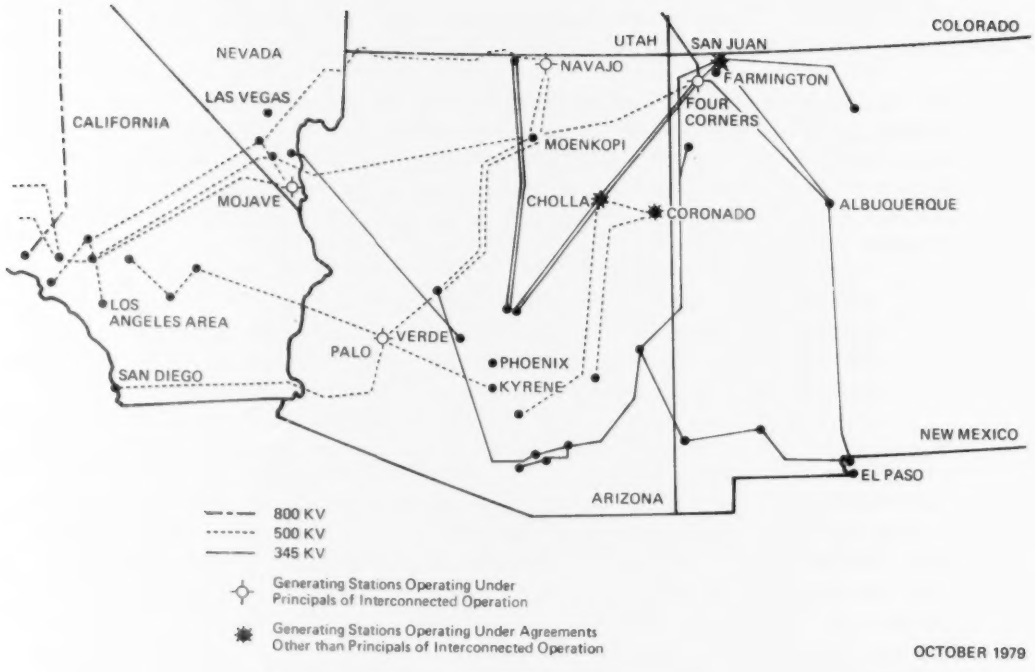

FIGURE 17--Principles of Interconnected Operation

meets annually to coordinate maintenance schedules for the Mohave Generating Station, Coronado Generating Station, Navajo Generating Station, San Juan Generating Station, and Four Corners Powerplant. The Advisory Committee prepares overall maintenance schedules and returns them to the Engineering and Operating Committees for approval.

ARIZONA PUBLIC SERVICE CO.-TUCSON ELECTRIC POWER CO. POWER POOL

The APS-TEP Power Pool is made up of the combined electrical systems of the Arizona Public Service Company and the Tucson Electric Power Company. Both APS and TEP are investor-owned utilities. Both, therefore, are subject to regulation by the Arizona Corporation Commission and FERC. Because of its sales to Mexico, APS is also subject to the Economic Regulatory Administration.

In the early 1960's APS and TEP were indirectly interconnected through the transmission system of the U.S. Bureau of Reclamation through which small interchanges of power were conducted. However, in recognition of the benefits obtained through increased coordination, the parties executed the APS-TEP Power Coordination Agreement (PCA) dated December 31, 1962 and a direct interconnection was constructed at the Saguaro substation. Although the agreement does not have the word "Pool" included in its title, it provides for all of the transactions included in most power pools. The Power Coordination Agreement provides for the following power pooling functions, which help achieve economies in costs and improvement in reliability of the interconnected systems.

1. Economy Energy--Service Schedule A of the PCA provides for economy energy interchange to fully utilize the most economical generating units available to reduce generation from more expensive units, to avoid more expensive energy purchases, and to avoid curtailing deliveries of secondary or interruptible power.
2. Spinning Reserve Interchange--Service Schedule A of the PCA provides for spinning reserve interchange to fully utilize spinning reserve capacity, which may be in excess of the spinning reserve requirements on one party's system when such operation is in the interest of overall economy or overall reliability in the combined systems of the parties.
3. Capacity Equalization--Service Schedule B of the PCA provides arrangements under which APS and TEP share installed reserves and the appropriate party is reimbursed by the party with relatively less margin for use of such reserves.
4. Reciprocal Emergency Assistance--Service Schedule B of the PCA establishes terms and conditions for reciprocal emergency

assistance when the power supply to consumers is threatened or curtailed in either system.

5. Transmission Service--Service Schedule E of the PCA establishes terms and conditions by which APS provides long-term transmission service to TEP for delivery of TEP's Four Corners entitlements.
6. Other--In addition, various Service Schedules of the PCA have provided, or are presently providing, benefits such as delivery of various power entitlements prior to completion of construction of certain transmission facilities, and joint use, ownership, and construction of transmission facilities.

The organization of the APS-TEP Pool is as follows:

1. Coordination Committee--Establishes general policies to be followed in coordination of the operation of the local systems of the parties; periodically reviews the prospective aggregate power requirements and arranges for investigations of additional generating capacity, other power sources, and related transmission facilities that will provide for such aggregate power requirements in a manner consistent with overall effectiveness and economy; and exercises general supervision and guidance over the Operating Committee.
2. Operating Committee--Establishes rules and standard practices for the guidance of system or load supervisors and other operating employees as to matters affecting interconnected operation, delivery of power, interchange of energy, use of reserve capacity, reciprocal emergency assistance, and other similar operating matters; establishes rates and standard practices as to determination of costs and expenses and of energy losses in connection with energy interchanges and other intersystem transactions; establishes detailed metering arrangements required in connection with transactions; and recommends installation of other or additional interconnection facilities to effect improved coordinated system operation.

The following table indicates the amount and type of generation resource capacity in megawatts for APS and TEP in 1978.

Party	Steam Coal	Steam Oil/Gas	Hydro-electric	Combustion Turbine	Combined Cycle	Total (MW)
APS	1,478	576	5	511	225	2,795
TEP	599	520	--	218	--	1,337

The following table indicates the 1978 peakloads for APS and TEP.

Party	Megawatts
APS	2,549
TEP	833
Total	3,382

ARIZONA PUBLIC SERVICE-UTAH POWER & LIGHT COMPANY INTERCONNECTION AGREEMENT

APS and Utah Power and Light Company (UP&L) signed the Interconnection Agreement (IA) on July 8, 1963. The following IA pooling services help to achieve economics in cost and improvement in reliability of the interconnected systems.

1. Economy Energy--Provides for economy energy interchange to use the most economical generating units available to reduce generation from more expensive units, to avoid more expensive energy purchase, and to avoid curtailing deliveries of secondary or interruptible power.
2. Reciprocal Emergency Assistance--Establishes terms and conditions for reciprocal emergency assistance when the power supply to consumers is threatened or curtailed in either system.
3. Transmission Service--Establishes terms and conditions by which APS and UP&L established an interconnection at the Four Corners 356-kV unit.
4. Other--Various expired service schedules provided such benefits as seasonal diversity exchange of power energy, firm power purchases, and transmission wheeling.

ARIZONA PUBLIC SERVICE CO.-NEVADA POWER CO. POWER COORDINATION AGREEMENT

APS and Nevada Power Company (NPC) signed the Power Coordination Agreement (PCA) on January 1, 1969. The following PCA pooling services help to achieve economics in cost and improvement in reliability of the interconnected systems.

1. Economy Energy--Provides for economy energy interchange to use the most economical generating units available to reduce generation from more expensive units, to avoid more expensive energy purchase, and to avoid curtailing deliveries of secondary or interruptible power.

2. Spinning Reserve Interchange--Provides for spinning reserve interchange to use spinning reserve capacity, which may be in excess of the spinning reserve requirements on one party's system, when such operation is in the interest of overall economy or overall reliability in the combined systems of the parties.
3. Other--Various expired Service Schedules provided such benefits as capacity equalization and reciprocal emergency assistance.

SOUTHWEST AREA TRANSMISSION PLANNING COMMITTEE

Significant coordination of transmission planning has been accomplished through the Southwest Area Transmission Planning Committee (SWAT). This committee meets regularly to evaluate the impact of anticipated future transmission plans, and has provided a forum for identifying pooling opportunities.

SWAT, first established in May 1977, was formed recognizing that certain transmission planning issues precipitated by the development of the Palo Verde, Cholla No. 5, Coronado, Springerville, and New Mexico plants, and the proposed second Northwest-Southwest d.c. Intertie could affect more than one utility. Members of SWAT include the Arizona Electric Power Cooperative, Arizona Public Service Company, El Paso Electric Company, Public Service Company of New Mexico, Salt River Project, San Diego Gas & Electric Company, Southern California Edison Company, Tucson Electric Power Company, and the Western Area Power Administration-Lower Colorado Area Office.

Technical study programs are periodically authorized by SWAT, and are conducted by various member utilities. These coordinating and transmission planning studies are funded by all of the member utilities with the major costs being equally allocated to the participating utilities directly involved in a specific study.

THE CACTUS POOL

HISTORY AND STATUS

The latest effort toward formalizing a pooling arrangement was initiated in August of 1974 by representatives of the Arizona Public Service Co., Salt River Project, Tucson Electric Power Co., Arizona Electric Power Cooperative, Inc., the Public Service Company of New Mexico, and the El Paso Electric Co. In April of 1975 a preliminary agreement was signed by officers of these companies. Economic and technical feasibility of coordinated planning of generation and transmission pooling was to be explored.

The exploration was vigorously pursued through activities by committees and subsequent meetings of a negotiating group. Twenty-two such meetings were held between October 1974 and May

1976, resulting in the development of proposed coordination agreements. Activities slowed after this, in part because of conflicting demands on limited manpower to devote to these pooling efforts. Interest continued, however, and there was a resumption of negotiations in 1977.

During 1977-79, negotiating delegates, under the direction of the Ad Hoc Executive Committee, spent a major amount of time on such issues as (1) developing reserve levels for the pool that would not appear to be a burden on any party, (2) alternate methods of sharing the pool reserves among the parties, (3) liability questions, and (4) ratemaking jurisdictional problems. It appeared that all problems had been resolved, except the sharing of the pool reserves among the parties.

However, by February 1979, during hearings conducted by the Arizona Corporation Commission, there was mixed support for the Cactus Pool among the participants. Despite considerable efforts, the Cactus Pool in its proposed form was not acceptable to the utilities, and by June 1979, all the participating utilities had withdrawn.

After June 1, 1979, some interest still prevailed for organizing the Cactus Pool. On September 7, 1979, the executive officers of the parties associated with the Cactus Power Pool negotiations met and agreed to devote 6 months of staff time to reform the Cactus Pool documents. In addition to the parties represented in the original negotiations, Community Public Service, Nevada Power Company, and San Diego Gas & Electric Co. were invited to participate. Four problem areas were identified. They were (1) installed reserve criteria, (2) the reserve-sharing formula, (3) the scope of the pool coordinator, and (4) planning scope.

A negotiating team was set up to review and resolve the above mentioned problem areas. Extensive negotiations were held and major philosophy changes were made. However, in January 1980 negotiations were again terminated.

The reasons for termination were that many of the parties had already acquired, or were actively seeking membership in the Inland Pool (causing a duplication of effort), and the same parties believed the reserve-sharing formula was still discriminatory. No future plans to reinstitute negotiations currently exist.

ANTICIPATED BENEFITS

Estimates of anticipated economic benefits of participation in the Cactus Power Pool Agreement, as envisioned in 1979, have been obtained from two of the prospective members. The Salt River Project estimated the present worth of identifiable benefits to it to be approximately $37.5 million for the period 1979-99. The

Arizona Public Service Company estimated that its savings over the same 20-year period would be as follows:

Benefit	Cumulative Savings (Million $)	Percent of Nonpool Total Revenue Requirements
Reserve Requirements	$556.0	2.9
Spinning Reserve Requirements	31.3	0.2
Incremental Loading on Poolwide Basis	150.0	2.0
Total	$737.3	--

CHAPTER 6
COORDINATION IN THE CALIFORNIA-NEVADA POWER AREA

INTRODUCTION

The California-Nevada Power Area is that general geographical area comprising the States of California and Nevada. The only areas excluded within those two States are small strips along their northern borders that are served by utilities operating in the Northwest Power Area.

In the Western Region, the California-Nevada Power Area is the second largest of the four power areas in generating resources as indicated by a winter capability of 40,103 MW as of January 1, 1980. (See Table 1.) Gas- or oil-fired steam generation alone amounts to 56 percent of the area's total resources, reflecting the area's heavy dependence on these scarce and expensive fuels. Conventional hydroelectric generation is important, especially in northern California, and amounts to nearly 22 percent of the California-Nevada Power Area's total resources.

Table 13 lists the generating utilities in the California-Nevada Power Area with 200 MW or more installed capacity.

The principal coordinating group operating in the area is the California Power Pool whose members are Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, all investor-owned utilities. In 1978, the municipalities of Burbank, Glendale, and Pasadena, all in southern California, formed a coordinating group among themselves for the limited purposes of transferring energy between members and providing occasional reserve support.

The Pacific Northwest-Southwest Intertie, described in Chapter 2, is an important facility to the California-Nevada Power Area, providing the means for capacity and energy sales and exchanges with Pacific Northwest utilities.

DEVELOPMENT OF COORDINATION IN AREA

NORTHERN AND CENTRAL CALIFORNIA

The history of electric power in northern and central California goes back to 1879, the year the California Electric Light Company was incorporated. From this early beginning numerous enterprising

TABLE 13--California-Nevada Power Area Generating Utilities[1]

Utilities with 200 MW or More Installed Capacity	Installed Capacity 1978 (MW)	Peakload 1978 (MW)
City and County of San Francisco[2]	293	--
State of California, Dept. of Water Resources	1,183	--
Pacific Gas and Electric Company	11,100	12,971
Placer County Water Agency[2]	211	--
Yuba County Water Agency[2]	331	--
U.S. Water and Power Resources Service (Lower Colorado Region)	1,175	576
U.S. Water and Power Resources Service (Mid-Pacific Region)[2]	1,162	--
Sacramento Municipal Utility District[2]	1,525	1,578
Sierra Pacific Power Company	555	563
City of Burbank	272	197
Glendale Public Service	306	195
Los Angeles Dept. of Water and Power	5,721	4,144
Nevada Power Company	786	1,254
City of Pasadena (Main)	301	191
San Diego Gas & Electric Company	2,402	1,981
Southern California Edison Co. (Main)	13,156	11,997

[1]Excludes 13 other utilities with generating capacities of less than 200 MW.

[2]Included in area system of Pacific Gas and Electric company. Five other generating entities, which are part of the area system of PG&E, do not have sufficient generating capacity to be included in the tabulation.

SOURCE: FPC Forms 1 and 12.

individuals and companies established small electric generating and distribution systems.

Much of the early history of electric power in northern and central California was associated with gold mining in the Sierra Mountains. The miners were the first water system builders in the foothills of the Sierras. As the stream-side claims were quickly exhausted, the miners began prospecting gravel deposits far from the creeks. Ditches to bring water to the dry diggings became a necessity. Later hydraulic mining became important, using even more water and requiring storage and canals. When hydraulic mining became regulated by the State Debris Commission in 1893, it became uneconomic, in most cases, to construct the required

debris-impounding dams. The existence of an extensive, unused water system and the timely development of the Pelton impulse water wheel provided the beginning of the hydroelectric system that eventually became the Pacific Gas and Electric (PG&E) system.

The family tree of PG&E has more than 500 ancestors--many of them associated with gold mining activities. Some of the more significant mergers into what is now PG&E were the following:

- San Francisco Gas and Electric Company (1905)
- Sierra and San Francisco Power Company (1927)
- Western States Gas & Electric Company (1927)
- San Joaquin Light & Power Company (1930)
- Great Western Power Company of California (1930)
- Coast Counties Gas & Electric Company (1954)

Incorporated in 1905, PG&E now serves in an area of approximately 94,000 square miles, the largest service area of any operating utility in the United States. It serves electricity to 3.5 million customers. The peak demand in northern and central California reached 14,948 MW in the summer of 1978.

For many years the power resources available to northern and central California were predominantly hydroelectric. In fact, it wasn't until the early 1950's that steam capacity exceeded that of hydroelectric. At the end of 1978 the resources available, based on an August dry year, were the following:

Resource	Megawatts	Percent Total
Hydroelectric	5319	33.2
Nuclear	938	5.9
Geothermal	502	3.1
Oil- & Gas-Steam	7309	45.5
Combustion Turbine	403	2.5
Cogeneration	179	1.1
Purchase	1400	8.7
Total	16,050	100.0

The hydroelectric capacity is still a significant component of the resources; however, its significance will decrease as total resources increase faster than hydroelectric additions.

Included in the northern and central California electric load areas are entities other than PG&E that generate electricity. The largest are the Sacramento Municipal Utility District (SMUD) and the U.S. Water and Power Resources Service (WPRS). Each of these

entities has contracts with PG&E that provide such mutual benefits as integration of generation resources.

In addition to SMUD and WPRS, there are contractual arrangements with several irrigation districts, San Francisco (city and county), the California Department of Water Resources, and other lesser producers of electricity. PG&E supplies 75-80 percent of the power used within northern and central California.

By many standards, northern and central California power systems could be classified as a power pool; the combined systems are as large as many existing pools. Through contractual agreements, the area generation is effectively integrated with benefits received by all parties.

SOUTHERN CALIFORNIA

The development of coordination in southern California has followed the history of the Southern California Edison Company. As early as 1918, 66,000-volt transmission lines linked the Edison Company to its neighbors and to other electric utilities as far north as the San Francisco Bay area. The drought of 1924 underscored the need for such interconnections when large amounts of power were exchanged either on a regular basis or during emergencies. During that time transmission lines were completed to interconnect every major utility in California.

Prior to 1948, power exchanges were limited because the pioneer a-c powerplants in southern California were built to produce 50 cycles of power and, while Edison had remained at 50 cycles, northern California and the majority of the surrounding systems were at 60 cycles. During 1948 the company converted from 50 to 60 cycles to better service their customers and to facilitate interconnections with surrounding systems in order to exchange larger amounts of power.

The first electric utility ancestors of the Southern California Edison Company date back to 1886 when two pioneer powerplants were constructed at widely separated locations in southern California. In March of that year, the Santa Barbara Electric Light Company began operating its steam-powered dynamos to light homes and businesses along State Street, the principal thoroughfare of Santa Barbara. In October of the same year, Charles R. Lloyd lighted up streets in Riverside and Colton with energy from his Highgrove hydroelectric plant, which was the first commercial water-powered electric plant in California.

Incorporated in 1909, the Southern California Edison Company provides electric service in a 50,000-square-mile area of central and southern California. This area includes some 800 cities and communities with a population of nearly 8 million people.

Edison's gross investment in utility plants totals more than $6.8 billion. The installed company-owned generating capacity at

the end of 1978 was 13,156 MW, of which 78 percent is accounted for by oil- and gas-fired generating units. SCE joint participation in coal-fired generating units accounts for another 13 percent, and 6 percent is in hydroelectric plants. The company's 80 percent interest in a joint participation nuclear plant accounts for the remaining 3 percent. In addition, Edison had 1547 MW of capacity under contract from other utility sources at year-end.

In March of 1981, a small group of San Diegans started a gas company which became a forerunner of the San Diego Gas & Electric Company. Starting with 89 gas customers, the company has grown so that by 1980 it was serving over 751,000 electric cutomers and 493,000 gas customers. Its service area has expanded to cover all of San Diego County and parts of Imperial and Orange Counties--an area covering approximately 4000 square miles and serving approximately 2 million people in 90 commuities.

The earliest major transmission connection San Diego Gas & Electric had to another utility dates back to 1918. In that year, construction of a 66,000-V line between San Diego and San Juan Capistrano tied the company to the Southern California Edison electric system. By 1980, this interconnection had increased to two 230,000 volt lines with firm capacity of about 450 MW.

From a total facilities investment of approximately $30,000 back in 1881, SDGE's 1979 gross plant investment (electric) exceeded $1.56 billion (total gross plant investment in gas is $235 million). The company has approximately 2735 MW of generating capability 86 percent of which represents oil- and gas-fired generating plants. Three percent of this capability is the company's 87-MW share of San Onofre Nuclear Generating Station's output. The remaining 11 percent of generating capability is contracted power purchases from other utilities and includes hydroelectric power from northern California and the Pacific Northwest, and coal-fired generation form Arizona.

CALIFORNIA POWER POOL DESCRIPTION

The original California Power Pool Agreement was executed on December 14, 1961, with the San Diego Gas & Electric Company (SDGE), Southern California Edison Company (SCE), and Pacific Gas and Electric Company (PG&E) as signatories. The agreement establishes a framework of operation for these companies with the goal of providing dependable and economical electric service to the public. This agreement was preceded by several years of observation of other power pools and of discussions, conferences, negotiations, and drafting sessions dating back to the mid-1950's. Thereafter, California Electric Power Company was merged into SCE. The present amended pool agreement between PG&E, SCE, and SDGE became effective on July 20, 1964.

The pool also actively involves the largest municipally owned utility in the United States--the Los Angeles Department of Water

and Power (LDWP)--in its meetings, deliberations, and operating practices, although LDWP is not a formal member. In turn, LDWP serves as liaison for the three smaller municipally owned utilities in Burbank, Glendale, and Pasadena. SCE also serves as liaison with its resale customers, including the Cities of Anaheim and Riverside. The end result is that the California Power Pool is the coordination vehicle for major generating entities in most of California, an area of about 140,000 square miles.

The agreement sets forth the contractual terms and conditions governing the interconnected operation of the Area Systems of the three utilities. It provides for each party to operate its system continuously and in parallel with each system of a party with which it shares an interconnection, and for the maintenance of interconnections in good operating condition. The agreement requires each party to provide minimum margins of capacity resources, energy resources, and spinning reserve, and makes provision for the pooling and sharing of the reserve margins possessed by the parties.

The definition of Area System according to the terms of the agreement is the following:

> Area System of a Party is its System together with (a) each other System of a Third Party with which it normally operates in parallel by means of facilities and under agreements which result in effectively integrating their loads and resources from an operating standpoint, and (b) generating plants in California, not included above, substantially all the output of which is sold to the Party and integrated into the Party's System." Through this provision the loads and resources of an integrated Third Party are included with those of the Party and will affect the obligations of the Party to the Pool. These Third Party systems, through their integration contracts with a Party, indirectly receive the reliability benefits of the pool backing up the supply of the Party with whom they are integrated.
>
> The Area System of PG&E includes: (1) its System, (2) the Systems of Central Valley Project (excluding Project pumping), Sacramento Municipal Utility District, City and County of San Francisco, those generating plants of East Bay Municipal Utility District, Merced Irrigation District, Oroville-Wyandotte Irrigation District, Tri-Dam Project of Oakdale and South Joaquin Irrigation Districts, Placer County Water Agency, and Yuba County Water Agency. The Southern California Edison Company Area System includes its System plus the System of the Metropolitan Water District. The San Diego Gas and Electric Company Area System includes only its System. Figure 18 depicts the service area of the California Power Pool companies and related utilities.

FIGURE 18--California Power Pool Companies and Related Utilities

A key point of the agreement is the concept that each party plans and constructs resources on a basis that provides at least certain minimum reserve margins. As a result, each party not only is able to fulfill its obligations, but may also rely upon the availability of such reserve margins from the other members if necessary. Each party is obligated (1) to operate its system in such a manner as to minimize disturbances that might impair service to the customers of other parties, (2) to maintain frequency at approximately 60 cycles within limits to be set by the Board of Control, and (3) to take care of its own reactive kilowatt-ampere requirements.

The services provided for in the agreement are all subject to certain specified conditions. A party can be required to furnish a service only out of its available capacity resources and then only to the extent that it can do so (1) without jeopardizing service to its own customers and other parties to which it is furnishing service of a higher priority, and (2) without interfering with obligations to third parties if such obligations existed at the time the pool was formed or created thereafter in accordance with the agreement.

The services provided for in the agreement are the following:

1. Short-Term Firm Service--By mutual agreement, a party may make capacity available and furnish energy to another party for up to 45 days, subject to renewal by mutual agreement. The effect of such service is to require the committed capacity to be excluded from the capacity resources of the supplier and, subject to some limitation to permit its inclusion in the capacity resources of the receiver. The purchase, sale, or exchange of firm capacity and energy for longer periods may be the subject of separate agreements.
2. Emergency Service--In the event of an emergency on the system of a party, that party has the right, if it is using all of its own spinning reserve, to receive service from the spinning reserves of the other parties for 2 hours. The amount of spinning reserve that may be demanded under this provision depends on the amount of spinning reserve the receiving party is obligated to maintain under the agreement. There is no charge for emergency service as long as the receiver does not require energy in excess of 2 hours, and does not exceed its spinning reserve entitlement at any time after the first 1/2 hour. However, the energy must be returned.

   If the emergency continues for more than 2 hours and if the party in trouble is using diligence to utilize its available resources, it is entitled to receive capacity and energy from the other parties for up to 60 days to replace its lost or interrupted capacity. The rate for emergency service that continues for more than 2 hours, or where the receiver exceeds its spinning reserve entitlement at any time after the first 1/2 hour of service is contained in a rate schedule.

3. Economy Capacity Service--By mutual agreement, a party may make capacity available and furnish energy to another party subject to notice of discontinuance sufficient for the receiver to place alternative capacity in service. The receiver is not, however, entitled to more than 24 hours notice. The effect of such service is to require the committed capacity to be excluded from the supplier's spinning reserve and subject to some limitation, to permit its inclusion in the resources of the receiver. The rate for such service is contained in a rate schedule.
4. Economy Energy Service--By mutual agreement, a party may sell economy energy to another party. Such service is interruptible without notice. The rate for such service is contained in a rate schedule.
5. Capacity Resources Standby Service--In the event of a capacity resource deficiency on the system of a party, that party may, if its own resources are fully loaded, call upon the other parties for capacity and energy for up to 7 days for the purpose of supplying firm customer loads. After the 7 days, the service can be renewed. The rate for such service is contained in a rate schedule.
6. Energy Interchange Service--Under this service, the intermediate system, which initially is that of the Southern California Edison Company, receives energy for the account of the receiver from the supplier of one of the aforesaid services (plus energy necessary to offset estimated energy losses) and delivers to the receiver an equivalent amount of energy so received for its account. The rate for such service is contained in a rate schedule.

The agreement requires each member to provide minimum margins of capacity resources, energy resources, and spinning reserve. These requirements, which are not intended to serve as standards of sound operating practice, merely establish the absolute minimum amount of resources believed necessary to preserve the reliability of the pool and to permit the furnishing of services provided for in Section 8 of the agreement.

The electric customers in the service areas of all three of the parties receive the following benefits:

1. Dependability of Service--In the event of an emergency loss of power supply sources on its own system, each party is able to provide more dependable service because of access to the spinning reserves of the other parties.
2. Reduction of Capital Expenditures--Each party has been able to reduce its capital expenditures below what they otherwise would have been because of (1) the resources credit that each of the companies takes through the sharing of installed reserves, and (2) the availability of the reserve resources of the other parties in the event of an emergency or scheduled outage.

3. Reduction in Operating Expenses--Each party has been able to reduce its operating expenses below what they otherwise would have been because they are able (1) to rely upon the spinning reserves of the other parties and (2) to draw upon the least expensive available source of power in the pool.

The pool provides valuable benefits to the public. Pool operations, which make available additional emergency assistance from the other pool members, benefits the public served by such a party by improving the reliability of service. In fact, although not specifically designed to do so, the pool may incidentally benefit interconnected third parties in cases of necessity. Those pool operations that reduce operating costs below what they otherwise would have been are passed on to retail and wholesale customers in the form of a lower cost of service.

The California Power Pool Agreement makes provision for an administrative body that is identified in the agreement as the Board of Control. The board usually meets monthly, and its specific responsibilities and powers are enumerated in the agreement. One of the most important functions of the Board of Control is to review, coordinate, and, if appropriate, approve the members' programs that provide resources to meet the forecasted loads.

Also in the agreement, provision is made for an Engineering and Operating Committee that is responsible to the board. This committee of the California Power Pool is the only standing committee specifically provided for in the California Power Pool Agreement. Its membership consists of the chief planners of each of the pool companies and the operating manager, who heads power supply activities. The Engineering and Operating Committee, which meets on an irregular schedule depending on the amount of activity demanding its attention, monitors activities under the pool agreement and makes recommendations to the Board of Control for their consideration and approval. It also serves as the working committee of the board, performing investigations and studies at the board's request.

The fact that planners and operators meet together and not as separate planning and operating committees, is a significant factor contributing to the cooperation between those companies under the pool agreement. This arrangement has narrowed the gap that frequently exists when operators and planners do their work apart from one another. For example, even though it is the primary responsibility of the planners to develop the loads and resources reports that are prepared every 6 months as required by the agreement, they receive input from the top operating managers, and it is the Engineering and Operating Committee as a whole that reviews the individual company reports and makes recommendations to the Board of Control. The planners have the primary responsibility for performing technical studies to establish the capability of transmission ties and the effects of various contingencies on interconnected system operation. The operators have the

responsibility to input information as to the actual operating experience, so that the experience can be compared with the predicted operation. This kind of interplay between planners and operators has contributed greatly to the continued level of reliability of the California systems.

Both the PG&E and SCE systems of and by themselves are as large as some power pools. For that reason, each of these areas can presently justify constructing the largest size units currently available from manufacturers. Therefore, the principal area of coordination is a result of the strong transmission interconnection that exists between the SCE and PG&E systems--three 500-kV a-c lines.

Under the pool agreement, there is an obligation for each of the parties to submit the latest forecast of loads and resources to the Board of Control at 6-month intervals (paragraphs 9.01 and 10.06(b)). Through these reports and other data each of the parties is familiar with the plans and expectations of the other parties. If there is any interest on the part of one party in participating in any way in a new resource, the opportunity is always there to be pursued in a bilateral way with that party.

A capacity resources deficiency occurs when the available capacity resources to a party are less than the capacity resources requirements under the pool agreement, that is, 110 percent of its peakload or 10-percent margin. There are other variations. The deficiency could be 110 percent of the peakload for that day, or it could be the sum of 105 percent of its peakload plus its capacity resources out of service because of scheduled maintenance for that same day.

An energy resources deficiency occurs when a party's energy resources during a month are less than its energy resources requirement. The energy resources requirement is defined as the actual energy requirements for that month plus the energy capability of the generating units out of service for scheduled maintenance, plus 50 percent of the energy capability of the largest generating unit included in the capacity resources and not out of service during that month. It should be noted that by definition, the energy resources of a party include the energy capability of its capacity resources, which includes capacity out of service. Therefore, the inclusion of the energy capability of units out of service on scheduled maintenance in its energy resources requirement has no net effect on any energy resources deficiency. In simple terms, the units have to serve the energy load, and, in addition, there must be provision for some amount of reserve energy. In the pool agreement, this provision is 50 percent of the energy capability of the largest generating unit not out of service during the month for each party. Finally, the agreement does not impose a penalty for an energy resources deficiency, it simply requires any party having a deficiency to use due diligence to correct the situation as soon as possible.

Each party is presently required to maintain a spinning reserve equal to at least 7 percent of its peak demand on that day.

However, a party does not incur a spinning reserve deficiency unless it goes below 5 percent. If a spinning reserve deficiency is incurred for two successive half-hourly determinations, the payment is $0.10 per kW-day. Several provisions excuse the deficient party from making any payment for such a deficiency for a specified time. The most commonly used provision for excusing payment is an emergency on a party's system.

If a party has an emergency and incurs a spinning reserve deficiency, it is entitled to draw on the spinning reserve of the other parties. There is no payment for emergency service as long as the deficient party neither receives energy longer than 2 hours after the emergency, nor exceeds its spinning reserve entitlement after the first 1/2 hour. The spinning reserve entitlement is equal to the spinning reserve requirement, which is 7 percent of peak demand for the day. If either of the two specified limits is exceeded, then the party will be considered as receiving emergency service at the rate provided in the appropriate schedule. If the emergency lasts for less than 2 hours, any energy received shall be returned to the supplier as soon as practicable at a mutually satisfactory time. Considering the small charges, if any, for spinning reserve deficiency, it is not considered a penalty, merely a service being purchased.

To achieve the anticipated benefits of a pool requires that each party bring to the pool a minimum level of reliability in its system. For example, the California Power Pool Agreement prescribes that the minimum level of installed reserve is 10 percent. If there were no enforcement provisions, one of the incentives to maintain the 10 percent would be lost. Those members that were maintaining 10 percent or greater would be supporting the deficient member, who would be achieving the benefits of not having installed capacity of its own by relying on that of the other members. That is, the benefits of the pooling would not be distributed on an equitable basis. Also, any party that lets its installed reserves drop to 10 percent would be doing so with the understanding that other members of the pool were maintaining at least 10 percent. Otherwise, they would need to have a larger reserve margin if they wished to maintain the same level of reliability.

In the area of maintenance planning, the scheduled outage of any major component of the bulk transmission system would be taken only after consultation with other systems that might be affected. The normal requirement for such an outage request is 72 hours, so that each of the parties can have adequate time to assess what the impact of that outage will be on its system. Typically, it is a practice of the parties to avoid scheduled outage of transmission facilities during periods of high customer requirements. By providing 72-hours notice, it is often possible for a system that has held up on some needed maintenance work to coordinate it with the outage request of another party. The pool companies regularly update their schedules for major generating unit maintenance. These schedules are currently updated as often as once a month, and the information is

exchanged to identify periods in which shifts in these maintenance programs are called. This practice prevents too many very large units from being out of service at the same time. This coordinating function has been extremely important in times of drought and at times when there was an interruption in the normal supply of fuel.

As previously discussed, the agreement specifically provides for six different types of service. The most frequently used are the economy capacity and economy energy services and the short-term firm service. Good communications at both the dispatcher and scheduling levels, as well as higher levels of operating management, are paramount to the success of operations under the California Power Pool Agreement. The companies have provided the dispatch organization with a highly sophisticated and redundant communication network for voice communication as well as channels of communication for indicating the status of the backbone EHV system that interconnects them. At those times of the year when loads are highest, the dispatchers communicate with one another by 9:00 a.m. each morning to provide a forecast of that day's anticipated load and the resources available to meet that load. Similarly, at midnight of each day, there is an exchange of information regarding the actual peak and the level of spinning reserve at the time of the peak for each of the major California electric utilities. As the day progresses, dispatchers quote incremental and decremental costs at delivery points, and indicate whether power is available for sale or would be purchased if the price were right. Whenever there is a significant loss of resources on any of the pool systems, this fact is communicated to the other dispatching organizations. Should loss of a major resource represent a threat to the reliability of one of the parties or to the pool, the overall reliability of the pool is almost immediately assessed to see if any other actions are required. In the event of sudden emergencies, the design features of each of the systems are automatically brought into play and the status of events made known to the dispatchers through modern data collection and display facilities.

The California Power Pool companies have not established a centralized dispatch. The board has examined this situation as they observed centralization and regional control being adopted in other regions of the country. The board's conclusions are that the sought after benefits of centralization can be achieved now with existing agreements. In some regions of the country the utilities involved in a pooling arrangement believed it was in their best interest to relinquish some of their prerogatives and assign them to another level of hierarchy. However, in view of the fact that within the PG&E control area there are a number of irrigation districts, a State project, a Federal project, and municipal and district projects that are integrated into the operation, it should be apparent that the PG&E power control group performs not only the function of centralized control for a large electric utility, but also many of the functions that typically get assigned to a pool dispatching office. By way of comparison, the PG&E control area

geographically and in terms of load is approximately equal to that of New England. Much the same could be said of the SCE system and its dispatch organization. PG&E, SCE, and SDGE are evaluating the potential benefits of increased pooling. In 1980, PG&E, SCE and the Los Angeles Department of Water and Power will participate in a modified Florida-type brokering scheme along with many other WSCC utilities.

The California Power Pool has no formal independent planning organization. As previously stated, the Engineering and Operating Committee is composed of system planners and system operators who are acutely aware of the opportunities for coordinated planning as well as for operations. There have been potential opportunities for joint participation in various projects. Often after investigation, the committee decided it was not in their best interest to follow up on them. For example, PG&E had the chance to participate in the Palo Verde nuclear plant in Arizona, but decided not to. Southern California Edison, on the other hand, did choose to participate. SCE and SDGE are joint participants in the San Onofre nuclear plant, including the two units now under construction. PG&E and SCE spent considerable time and effort, along with the Los Angeles Department of Water and Power, in planning the San Joaquin Nuclear Project before it was dropped for environmental reasons. Currently, SCE and PG&E are jointly studying the feasibility of participating with Nevada Power Company and the City of St. George in the proposed Harry Allen-Warner Valley coal-fired project (2500 MW). Although not promoted under the auspices of the California Power Pool, the same three utilities worked closely together in planning, constructing, and operating the Pacific Intertie. They believe there are ample opportunities for bilateral or even trilateral cooperation among the companies.

As discussed earlier, both PG&E and SCE are able to install and use the larger generating units now available. This fact reduces the need to have project partners that would be desirable or even necessary if the utilities were smaller.

EVALUATION OF CURRENT POOLING

The evaluation of the benefits being achieved by the coordination of planning and operation of the California Power Pool systems is not a simple task. To obtain an accurate evaluation would require the determination of what each utility would have done without the existence of the other pool members. Because there has been no need to plan the system in this manner, only assumptions by experienced system planners can be made.

PG&E, SCE, and SDGE have calculated what they believe are conservative "ball park" benefits from membership in the California Power Pool. In addition, SCE has calculated benefits it realizes from coordination outside the California Power Pool. Following is a discussion of those benefits and calculations:

PACIFIC GAS AND ELECTRIC COMPANY BENEFITS

PG&E considered only four benefits they receive, however, they believe these account for the bulk of the total benefits. The four benefits are (1) capacity savings through reserve sharing, (2) savings in no-load fuel for reduced spinning reserve requirements, (3) savings due to the installation of larger units, and (4) savings from energy transactions.

These benefits are attributed to being a member of the California Power Pool, however, they could be achieved through contractual agreements without the creation of a formal pool. PG&E neither considered the significant savings in transactions with the Pacific Northwest over the Pacific Intertie, nor attempted to quantify the benefits being achieved by all entities in northern and central California through contracts that integrate area generation resources.

Following is a brief discussion of each of the benefits considered using 1978 conditions.

Capacity Savings Through Reserve Sharing

PG&E currently counts on the California Power Pool for 600 MW of "perfect" support in planning its resource expansion. This amount may be changed after the completion of the pool study now underway.

If PG&E were an isolated system, the utility would have had to add approximately 690 MW (600 + 15 percent) of capacity to maintain the reliability now being achieved. To quantify this benefit, PG&E has used the average installed cost of 165-MW and 330-MW reheat units completed during 1955-64. The utility believes these are conservative (low) costs due to the earlier time frame, but they are the most representative units available. Not included are costs for transmission outlets and fuel storage facilities at the plants. The units selected and their installed costs are as follows:

Unit	Total MW	Dollars per kilowatt hour
Morro Bay 1 and 2	332	145
Morro Bay 3 and 4	676	101
Contra Costa 6 and 7	680	90

Weighted average = \$105/kW
Capital cost = 690,000 x \$105 = \$72.45 million
Annual cost = \$72.45 x 10^6 x 0.15 = \$10.87 million
Rounded figure = \$11 million

Savings in No-load Fuel for Spinning Reserve

Without spinning reserve support from the pool PG&E would be required to operate extra spinning reserve. It has to be assumed the utility would carry an additional 3 percent. Using a load duration curve, PG&E found that the average load for 1979 is 9000 MW. Therefore, the average additional spinning reserve would amount to 270 MW.

To calculate the no-load fuel it was necessary to assume the type of unit(s) that would be placed on spinning reserve. Different types of units would be committed to spinning reserve at various load levels. For simplicity PG&E has assumed that the nonreheat units would represent the average no-load fuel consumption. This consumption is about 18.5 barrels per hour for a 116-MW unit. It is further assumed that fuel cost is $18 per barrel.

The estimated annual cost for the added spinning reserve is:

$$\frac{270}{116} \times 18.5 \times 8760 \times \$18 = \$6,790,000$$

Rounded figure = $6.8 million

Savings Due to Installation of Larger Units

Today the northern and central California area, having a peakload of 15,000 MW, can economically install the larger size generating units being offered by manufacturers. This was not true at the time they committed to the installation of 750-MW units at Moss Landing and Pittsburg, or the 900-MW and 1100-MW nuclear units at Rancho Seco (SMUD) and Diablo Canyon, respectively. Assuming these units would have been two-thirds the size of those actually installed, it is estimated the cost per kilowatt would have increased by $25 per kilowatt.

Moss Landing No. 6	750 MW
Moss Landing No. 7	750 MW
Pittsburg No. 7	750 MW
Diablo Canyon No. 1	1100 MW
Diablo Canyon No. 2	1100 MW
Rancho Seco	900 MW
Total	5350 MW

Therefore capital cost saving equals:

5,350,000 x $25 = $133,750,000

Annual cost = $133,750,000 x 0.15 - $20 million

Savings From Energy Transactions

Time availability did not permit PG&E to thoroughly investigate the savings resulting from economy energy and other types of energy transactions. In most situations where energy was purchased in 1978, it was because PG&E needed it to meet customer load due to the delay in getting the Diablo Canyon unit online.

During 1978, sales to other pool members totaled approximately 103 million kWh. PG&E purchased about 27 million kWh. They sampled many of these sales transactions and determined that the incremental/decremental difference was typically 5 mills per kWh. Therefore, the total benefits from sales amounted to approximately $520,000.

PG&E also had sales and purchases of economy capacity and short-term firm capacity amounting to slightly over $1 million. It is difficult to place a monetary value on capacity transactions required to ensure areawide reliability.

From the foregoing it is reasonable to state that the PG&E area benefited in 1978 in the range of the following:

Reserve sharing	$11.0 million
Spinning reserve	6.8 million
Larger units	20.0 million
Economy transactions (low)	0.5 million
Total	$38.3 million

It is clear that in 1978 most of the pool benefits came from savings other than economy transactions. It should be recognized that there is little load diversity among the California systems, and that oil, the incremental fuel, is near the same price for all pool members. Because of uncertain future supply, economy energy sales often cannot be made because the potential seller does not wish to run the risk of depleting his fuel inventory.

PG&E believes that this is a reasonable rough estimate of its benefits of coordination through the California Power Pool, although the estimates may be on the low side (primarily in the reserve-sharing benefits). Because PG&E only had costs for units installed prior to the time reserve sharing was included in the utility's resource planning, $105 per kW in pricing the reserve sharing is thought to be low. If the company had to replace the reserve support with today's cost of capacity, the cost would be several times the value used.

SOUTHERN CALIFORNIA EDISON COMPANY BENEFITS

Listed below are the quantifiable benefits that Southern California Edison achieved through its pooling activities during 1978.

Activities Within the California Power Pool (CPP)

1. It is accepted by Edison, for resource planning purposes, that without the pool, 300,000 kW of additional capacity would have been required during 1978 at an annual combustion turbine cost of approximately $50 per kW-year. Subtracting the actual costs incurred in 1978 for the purchase of capacity from the CPP ($279,000) results in an approximate savings of $14.727 million. In addition, Edison will use a total of 600 MW for resource planning purposes beginning in 1984. This will increase the savings in future years by around twofold.

   Savings $14.7 Million

2. If Edison were to operate as an isolated system (i.e., no pool), a spinning reserve larger than the 7-percent value allowed by CPP would have been required during 1978 to cover the loss of Edison's largest single contingency and to maintain necessary regulating margins. Based on the no-load fuel costs incurred by having the additional units on line, Edison realized an additional $1.5 million savings.

   Savings $1.5 Million

3. By utilizing the economy capacity feature of the California Power Pool and not using older high-cost generating units, Edison realized the following savings during 1978. The amount is based on the reduction in startup and no-load fuel costs of units not started up and operated, compared to the payments for the economy capacity.

   Savings $1.0 Million

4. Through the provisions of the California Power Pool allowing for economy energy interchange, Edison purchased over 38,000 MWh of energy at a savings of over $300,000.

   Savings $0.3 Million

TOTAL CALIFORNIA POWER POOL SAVINGS $17.5 Million

Activities Outside the California Power Pool

1. Edison has entered into a capacity exchange arrangement with BPA wherein Edison is supplied with 550 MW of capacity and energy for a 10-hour period each day. For this service Edison is obligated to deliver to BPA up to 1.375 million MWh annually in addition to the onpeak energy it received under the 550 MW of capacity. Using an annual combined cycle cost of approximately

$125 per kW-year and subtracting approximately $29.6 million for the return energy, results in an approximate savings of $39.15 million.

Savings $39.2 Million

2. Under various contracts, Edison was able to purchase approximately 6034 GWh of economy energy and 1387 GWh of "dump" energy from other utilities during 1978. These arrangements produced a net savings of $91.5 million and reduced Edison's oil requirements by approximately 12 million barrels of low-sulfur fuel oil.

Savings $91.5 Million

3. Edison has an arrangement with Portland General Electric whereby Portland supplies 100 MW of capacity for 10 hours during Edison's summer months, and Edison in turn does the same for Portland during their peak winter months. This agreement defers the installation of at least 100 MW of summer intermediate load capacity. Using an annual combined cycle cost of $125 per kW-year, this equates to an annual savings of approximately $12.5 million.

Savings $12.5 Million

4. Edison entered into an agreement with Portland General Electric concerning the exchange of energy and capacity in 1978. This was a coordination arrangement in that Edison provided PG&E 225 MW of capacity and 431 GWh of energy for the last 3 months of 1978. In exchange, Portland will provide Edison with 4 months of 225-MW summer capacity and 127 percent of the delivered energy during 1981. The savings in oil dollars alone are $13.3 million.

Savings $13.3 Million

TOTAL SAVINGS FROM ACTIVITIES OUTSIDE CPP $156.5 Million

The aforementioned dollar benefits for both CPP and non-CPP total $174.0 million for the year 1978.

In addition to the quantifiable benefits, many nonquantifiable benefits have been achieved through inter- and intraregional pooling/coordination. An example of this is that within the last few years, without the emergency services provided by other utilities within WSCC--and in particular the California Power Pool--firm loads would have been curtailed during times of capacity shortages.

Other SCE pooling/coordination activities currently in practice include:

- Integrated operations with resale cities and water agencies
- Joint participation with other utilities in baseload generation facilities and associated transmission systems
- Formulation of an intrastate capacity shortage contingency plan involving the sharing of reserves

SCE is also actively involved in many future pooling/coordination activities that are currently being formalized:

- Unit commitment within the California Power Pool
- Integration of major unit maintenance scheduling within the California Power Pool
- Participation in the WSCC "Power Brokering" trial system

SAN DIEGO GAS & ELECTRIC COMPANY BENEFITS

SDGE considered that it received benefits from pooling activities during 1978 through (1) reduced capacity requirements, (2) reduced spinning reserve requirements, (3) economy energy interchange, and (4) economy capacity purchases. These savings were estimated to total $8.6 million as detailed below.

Capacity Benefits

Without the benefit of interconnected operation, the planning criteria for generation reserves would be the two largest contingencies instead of the less restrictive 20-percent criteria. In 1978 this would mean a savings of 111 MW of installed generation. If this capacity cost can be assumed to be equivalent to an annualized combustion turbine cost ($60 per kW per year) the savings due to this reduced capacity requirement would be $6.7 million.

Savings $6.7 Million

Spinning Reserve

Isolated system operation for SDGE would require a spinning reserve larger than the 7-percent value allowed by the power pool to cover the loss of the single largest contingency (287 MW). Based on the no-load fuel costs incurred by having the additional units on line, SDGE realized a $1.6 million savings in 1978.

Savings $1.6 Million

Economy Energy

Through the provisions of the California Power Pool allowing for economy energy interchange, SDGE purchased over 48,700 MWh of energy at a savings of approximately $98,000.

Savings	$0.1 Million

Economy Capacity

The economy capacity feature of the California Power Pool permitted SDGE to purchase an annual average capacity of 25.3 MW in 1978. This low-cost capacity provided a savings of $190,000.

Savings	$0.2 Million
TOTAL SAVINGS	$8.6 Million

A DIVERGENT VIEW ON THE CALIFORNIA POWER POOL

The preceding discussion of the California Power Pool (CPP) is, for the most part, the result of the effort of two task force members, both of whom are from investor-owned utilities that are members of the CPP. Therefore, to the extent that the discussion includes evaluation of the pool's effectiveness, it might be argued that the discussion would reflect to some degree the perspective of the pool members.[1]

Another task force member, who is from an agency representing a municipal segment of the utility industry in California, views the effectiveness of the CPP differently. In his view the CPP serves, essentially, as a mechanism for coordination between the control areas of the two larger member utilities and does not take advantage of the economic or the energy conservation advantages of coordinated operation. It is also his view that the CPP does not optimize the use of facilities and resources on a State or regional basis.

This divergent view of the CPP was expressed in a letter from the task force member to the task force chairman, dated January 14, 1980. Although certain comments offered were made with respect to an earlier draft of this report and are no longer pertinent, the letter is reproduced in its entirety to ensure that the member's

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[1]As explained in the Foreword, each member of the task force served primarily as an individual, contributing personal knowledge and interpretations and providing information on industry activities and problems on the basis of his expertise. It could be expected, however, that members reflected the views of their own industry segment to some degree.

views are preserved in proper context. The January 14, 1980 letter and a response to it from another task force member dated November 25, 1980 are included in Appendix C.

The matter of the California Power Pool is one issue being heard in an ongoing FERC consolidated proceeding in Dockets Nos. E-7796 (Phase II), E-7777, P-2735, and P-1988.

OUTLOOK

The four major California utilities recently completed two studies to determine the additional reliability and economic benefits that could be attained by increasing coordinated planning and operation above current levels. Based on future generation programs as of June 1978, the planning study for the period 1981-1990 showed that savings from economy energy transactions among the four utilities would be $30-40 million per year. These are the savings of fully pooled operation (one world) compared to the sum of four isolated systems. The study further showed that if economy transactions are made for all fuel differentials of 0.4 mills per kWh or greater (differential in incremental costs of energy between buyer and seller after accounting for transmission losses as provided in the California Power Pool Agreement), 97 percent of the potential savings can be achieved. To provide a more accurate means of tracking the differentials in incremental costs, the utilities are currently installing telemetering between pool members to transmit real-time incremental cost data.

Although advanced state-of-art programs and modeling techniques were used in the recent evaluations, the California Power Pool members and the Los Angeles Department of Water and Power (LDWP) recognize that further study is required to refine certain areas revealed by the study. The four utilities are now in the process of developing a program for additonal studies.

Furthermore, PG&E, SCE, and LDWP are projecting the installation of large baseload generating units as joint projects with smaller utilities located within California and adjacent States, including Nevada. Included in this group of joint projects is PG&E's Montezuma coal-fired plant, comprising two 800-MW units scheduled for installation in the late 1980's. The other participants are not identified as yet, but this project should provide the area's smaller utilities with the opportunity to benefit from large-scale generation.

The California Power Pool utilities placed into service a statewide unit commitment procedure in June 1980. Transactions have taken place under this procedure which reduced statewide costs and allowed for needed maintenance during weekends. The major attempt has been to reduce the use of inefficient combustion turbine and non-reheat generation.

CHAPTER 7
REGULATORY AND LEGISLATIVE IMPACTS ON REGIONAL ELECTRIC COORDINATION

INTRODUCTION

The Western Region, embracing the electric utilities in 9 States completely, plus portions of 5 additional States, has a multiplicity of regulatory authorities within its bounds. Within each State, utilities must comply with regulations of several agencies not always in accord on electric utility matters. The task force considers that regulation can have a substantial impact on electric power coordination in the Western Region. Federal agency regulatory and environmental proceedings generally are not coordinated with one another or with similar State and local proceedings.

The following discussion, gives a sampling of the views of State regulatory agencies and their respective philosophies regarding coordination. Each agency apparently endorses the benefits achieved from coordination and pooling; however, views have not been expressed with respect to the relation of individual State regulation to multistate pooling.

REGULATORY AUTHORITIES

The Western Conference of Public Service Commissions (WCPSC) has assigned its Staff Subcommittee on Electric Power Supply to review data and information relating to electric utility generation and transmission plans and operations, and to make recommendations on improved power pooling efforts. WCPSC members are the following:

- Alaska Public Utilities Commission[1]
- Arizona Corporation Commission
- California Public Utilities Commission
- Colorado Public Utilities Commission
- Hawaii Public Utilities Commission[1]
- Idaho Public Utilities Commission
- Montana Public Service Commission
- Nevada Public Service Commission
- New Mexico Public Service Commission

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[1]Alaska and Hawaii are not within the geographical limits of the Western Region as defined in this report.

- o Oregon Public Utility Commissioner
- o Utah Public Service Commission
- o Washington Utilities & Transportation Commission
- o Wyoming Public Service Commission

REGULATION OF RATES

A number of aspects of both FERC and State commission ratemaking can serve as significant incentives or discouragements to power pooling. A particular issue is recovery of coordination costs and sharing of coordination benefits between ratepayers and stockholders. State commission treatment of transmission and fuel costs can significantly affect utilities interest in power pooling. FERC and State commission rules may differ on allocation of costs involved in power exchange transactions. Utilities should have reasonable assurance that recovery of costs can be anticipated through a consistent application of cost allocation principles. Some State commissions are exploring the development of incentives for powerplant productivity, some concepts of which might be extended to power pooling. The FERC and State commissions are also responsible for ratemaking procedures that consider the reasonableness of fuel costs. PURPA (Sec. Nos. 115 and 208) also requires periodic review of automatic adjustment clauses by both FERC and State regulatory authorities.

POWERPLANT SITING

Many State agencies perceive that the development of additional interconnections and expanded power pooling will result in the siting of many facilities within States having major coal reserves. Several State agencies, including some in Colorado, Idaho, Montana, and Utah, have recommended limitations on construction of new generating facilities for export of electric energy to other States. On the other hand, most, if not all of the western State regulatory authorities have indicated support for more interconnections and increased power pooling that would increase reliability, reduce oil consumption, and reduce utility costs in general.

OTHER REGULATORY ACTIVITIES

Section 205(a) of PURPA provides that FERC may exempt electric utilities from any provision of State law or regulations that prohibit or prevent voluntary coordination between utilities. These provisions are viewed by State regulatory authorities as those which might be exercised if disputes arise between several States. Where central dispatching or other power pooling economies are available

within a State, the State regulatory authority may encourage such power pooling. FERC can encourage and support individual State regulatory and legislative initiatives that encourage intrastate power pooling as well as encourage interstate pooling opportunities.

State utility commissions are exploring the merits and mechanisms for encouraging better utility performance and increased efficiency through effective incentives. One effort is being performed by the National Regulatory Research Institute, an independent research organization, originally founded under the auspices of the National Association of Regulatory Utility Commissioners (NARUC). Such incentives can serve to encourage utility pursuit of economics available through electric power pooling.

WCPSC MEMBER POSITIONS

Following are statements of the positions of State regulatory authorities in Arizona, California, Colorado, Montana, Nevada, and Washington on items that relate to the pooling of electric utilities in the western States.[2] The regulatory authorities in the other five States within the WCPSC (Alaska and Hawaii excepted) were invited by the WCPSC Task Force member to provide statements but none responded.

ARIZONA CORPORATION COMMISSION

Power Pooling

The Arizona Corporation Commission is contemplating a transmission line study for those transmission and/or generating utilities that operate within State boudaries. Firm power contracts (in and out of the State), as well as economy interchanges will be considered. Of primary interest are pooling agreements between two or more companies, and their effect on the reserve status of each.

Powerplant Productivity

The Arizona Corporation Commission is currently collecting plant productivity data on each generating unit operated by a company

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[2]Represents the view of the identified authorities and not necessarily the position of other State agencies.
under its jurisdiction. Salt River Project, which is not under the commission's jurisdiction, will also be approached. This data will be valuable in determining the capability of the statewide generating system.

best copy available

Powerplant Siting

Arizona has, by statute, a Siting Committee that reviews proposals of planned 115-kV or greater transmission lines or powerplant sitings, in which a complete environmental statement is offered for three proposed sites. No Arizona agency has gone on record for limiting construction of new generating facilities to export electrical energy, nor has an out-of-state utility proposed construction of a powerplant within Arizona solely to benefit out-of-state users.

CALIFORNIA PUBLIC UTILITIES COMMISSION AND CALIFORNIA ENERGY COMMISSION

The California Public Utilities Commission (CPUC) regulates rates, financing, service, safety, and operations of investor-owned electric utilities. The CPUC issues Certificates of Public Convenience and Necessity for new powerplants and is the lead agency for all out-of-state plant and transmission line certification.

The California Energy Commission (CEC) has approval authority for new thermal generating facilities and related transmission facilities proposed by both public- and investor-owned utilities in California, and is the lead State agency for these facilities' Environmental Impact Reports. CEC also forecasts electric and gas energy demands; establishes conservation standards for new buildings, appliances, and utility load management; and promotes the development of alternative energy resources. The commission is required to assess all utility plans for interstate or interregional pooling, and to make recommendations to the State Legislature and Governor on the availability of purchased power and on power pooling.

The Energy Commission, with financial assistance from the DOE Economic Regulatory Administration, is conducting a comprehensive study of power pooling. This study includes three separate reports: (1) "Costs and Benefits of Power Pooling in California," prepared by Systems Control, Inc., has been released; (2) "Institutional Factors Affecting Increased Power Pooling in California"; and (3) "Western United States Power Pooling, Institutional Factors," both prepared by CEC staff, will soon be released.

The CPUC has been working with CEC and the four major California utilities, three investor-owned and one municipally owned, to increase pooling activities with the objectives of higher operating reliability and reduced oil consumption. As a result of these efforts, utilities have committed themselves to institute the following new programs during the summer of 1980:

1. The California Power Pool companies will begin a statewide "unit commitment" program, which will be observed by the dispatchers of each of the systems.

2. The California Power Pool companies will exchange and display incremental costs in "real time."
3. PG&E, SCE, and LDWP will participate in a western regional trial operation of a modified Florida energy brokering arrangement.

COLORADO PUBLIC UTILITIES COMMISSION

Position Statement on Regional Coordination

The Colorado Public Utilities Commission regulates the rates and financing of investor-owned utilities, rural electric cooperatives, and that portion of municipal utility service which is supplied outside the corporate limits of the city. The commission also grants certificates of Public Convenience and Necessity for the construction of major new facilities in the State. Recently the legislature has given the commission the responsibility to submit any energy report to the legislature and to the Governor every 2 years. This report is to include a 10-year forecast on loads and resources for all electric utilities in the State. This commission has also begun to collect powerplant productivity data as a means of monitoring the utilization of existing resources.

As a result of its ongoing generic hearing on electric rate design, the commission has had recent opportunity to consider the entire issue of regional coordination. Further hearings on this issue are in the process of being held. In its initial decision, however, the commission has encouraged, to the maximum extent possible, coordinated planning and operations, and indicated that the degree of coordination will be considered in future energy cost adjustment hearings and in future applications for Certificates of Public Convenience and Necessity for the construction of new facilities. In that same decision, the commission stated that it intends to avoid any actions that will encumber coordinated planning for bulk power resources by Colorado and non-Colorado utilities.

MONTANA PUBLIC SERVICE COMMISSION

Responsibilities

1. Utility ratemaking--The five-member Montana Public Service Commission is elected by districts, and regulates traditional rate and service matters for private electric utilities. Five utilities with Montana operations qualify under PURPA standards as major utilities. Montana Power Company (MPC), Montana-Dakota Utilities Co. (MDU), and Pacific Power and Light (PP&L) have substantial Montana operations; Washington Water Power (WWP) and Black Hills Power and Light have very minor Montana operations. MPC, PP&L, and WWP are members of the Northwest Power Pool; MDU

is a member of the Mid America Power Pool (MAPP); and Black Hills is a member of the Rocky Mountain Power Pool (an "operating" or less formal pool).

2. Major Facility Siting Act--A seven-member lay board appointed by the Governor comprises the Board of Natural Resources and Conservation. The board has primary authority in considering a siting application. It must determine the need for generation and transmission facilities and whether or not the facilities meet the "minimum adverse environmental impact" requirement of Montana law. Siting is a contested case proceeding. The Department of Natural Resources and Conservation prepares the environmental impact statement for Montana.
3. Air and water quality--The Board of Health and Environmental Sciences consists of seven members appointed by the Governor. Its responsibility is to certify compliance with air and water quality standards within the Major Facility Siting Act proceedings. The Major Facility Siting Act was amended by the 1979 legislature and as yet no applications have been processed under the revised law.
4. Land reclamation and State coal leasing--Department of State Lands.

Philosophy and Concerns

Montana law and the current regulatory philosophy of the Montana Commission bear upon issues involving power pooling, exchange pricing on out-of-state sales for ratemaking purposes, siting, generation alternatives, conservation emphasis, and related matters. Within its legal responsibilities, the commission takes an active and aggressive role in the activities of jurisdictional utilities.

The Montana Commission has taken an aggressive position in opposition to a series of Northwest Energy Bills. Copies of pertinent testimony on that legislation provide insight into the commission's insistence that Montana be treated as a full partner in any regional decisions having an impact on the State.

Montana accepts its responsibility to provide substantial energy resources for the Nation. That primary energy source however, is coal, not electricity. Montana is clearly ready to mine the coal and reclaim that land, but to suggest that it must also construct minemouth generating facilities, absorb the associated air pollution (which affects its native vegetation and the lands it is attempting to reclaim), supply enormous quantities of water for facilities from its semiarid prairies, and absorb the impact of multiple transmission corridors--all so that electricity, not primary energy, is available to load centers--is irrational and unfair.

NEVADA PUBLIC SERVICE COMMISSION

Powerplant Siting

The Nevada Public Service Commission exercises regulatory authority, pursuant to Nevada State Law (NRS704.820) under the "Utility Environmental Protection Act," concerning powerplant sitings. In addition, the commission considers, on a case-by-case basis or in generic hearings, current regulatory issues including power pooling, generation alternatives such as direct load management, exchange pricing, and ratemaking incentives to encourage conservation. The responsibilities in this regard include assurance that adequate and reliable service is available at just and reasonable rates that (1) minimize the burden on the ratepayers, (2) do not deteriorate the financial and operative standing of the utility, and (3) provide for the economically efficient use of energy.

The Nevada Public Service Commission has in the recent past considered and decided requests by the State's two major electric utilities to construct additional generation facilities in both northern and southern Nevada.

In Docket No. 1984 (decided March 26, 1979), Sierra Pacific Power Company was authorized to enter into a joint venture with Idaho Power, whereby two 250-MW coal-fired generating units would be constructed at Valmy, Nevada. In Docket No. 732 (decided June 29, 1977), the commission had previously approved construction of the first 250-MW unit at Valmy to be constructed by Sierra, and in Docket No. 1984, the commission authorized the construction of another 250-MW unit and approved the joint venture arrangement between Sierra and Idaho power.

Furthermore, in Docket No. 1771 (decided September 4, 1979), Nevada Power Company of Las Vegas requested that the commission authorize the construction of two 75-MW peakshaving units to be located in Las Vegas at Clark Stations 6 and 7. In deciding both the Valmy and Clark cases the commission analyzed the desirability and feasibility of power pooling. The statutes of the State of Nevada do not directly address the issue of power pooling, thus the commission may use its discretionary powers in considering that issue.

The commission, in both of the aforementioned dockets, determined that Nevada's interests would be best served if power pooling were aggressively pursued by Nevada electric utilities. In the Valmy cases, it is quite clear that power pooling is an integral part of the contractual relationship existent between Sierra Pacific and Idaho Power. In southern Nevada, the commission has gone on record in Docket No. 1771 and other cases encouraging Nevada Power Company to actively pursue power pooling as a source of energy in meeting peak summer demands in its system.

The Nevada Commission believes that power pooling, integrated interstate power systems, and cooperation between utilities and their respective State regulators are in the public interest. Nevada will continue to strive to ensure that utilities pool their resources in meeting the energy needs of the people of the State of Nevada.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

The Washington Utilities and Transportation Commission encourages the utilities under its jurisdiction to participate in power pooling and economy exchanges of energy. Because the electric utilities in Washington rely heavily on hydroelectric energy, the water conditions have a substantial effect on the utilities' expenses for purchased power as well as their revenues from energy sales. During a rate proceeding, the utilities normalize expenses and revenues for the test year. This normalizing process adjusts expenses and revenues to levels that would have been attained had the test year been normal. Normalized sales and purchases are determined by a computer simulation of average water conditions coupled with known loads, markets, etc. Because the commission must regulate rates in the public interest, the most efficient operation of the utilities, which will include economy exchanges, will be a part of the assumptions in the analysis of a rate increase request.

Powerplant siting is handled by the Energy Facility Site Evaluation Council and by the Governor. The council considers all factors relating to site suitability, plant design and safety, and more, but does not consider need. The final decision is made by the Governor. The State Energy Office also conducts power planning and coordination activities.

CHAPTER 8
IMPEDIMENTS TO INCREASED REGIONAL COORDINATION

The discussions presented in previous chapters on power pooling in the Western Region clearly indicate that the interconnection of transmission facilities and the coordination of the planning and operation of generating resources by utility systems have existed in the region for a number of years. These arrangements have yielded significant benefits in the past, and their economic effectiveness is continuing today. From the preceding discussions it is also equally apparent, however, that both the level and degree of coordination vary widely from pool to pool throughout the region. These variations suggest that there might be yet unrealized benefits to be achieved from increased coordination.[1] If future benefits from increased coordination could be identified and quantified with a reasonable degree of certainty, the task force believes that there would be no hesitancy on the part of the affected utilities to explore means to achieve those benefits. In the process, however, the utilities may encounter impediments that would tend to inhibit further integration despite expected economic benefits. The purpose of this chapter is to briefly discuss some of the common impediments to increased coordination, to summarize the more significant impediments that were identified by the task force as being especially constraining in the Western Region, and to suggest ways by which the more significant impediments might be eliminated or ameliorated.

To increase the level of coordination in a power pool, or to form a new power pool, requires concerted effort and dedication to mutual objectives by all participants. In the process there are many impediments--institutional, financial, regulatory, legal, technical, and other noneconomic--that combine to frustrate the

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[1]That the level of benefits from pooling necessarily increases as the level of coordination increases is not an axiom universally accepted by task force members. Additional benefits of pooling are hard to quantify and justify economically in areas of the Western Region where good planning and operating coordination both exist, even though these practices are pursued in a multiplicity of "lower level" arrangements.

efforts. A list of some typical nonregulatory impediments would include the following:

- Management may be reluctant to yield its prerogatives. Interutility agreements, of necessity, require some concessions from all participants in order to achieve an equitable distribution of obligations and benefits. With each concession made there is a corresponding erosion of management's self-directing freedom. Management may be reluctant to give up that autonomy.
- A utility's individual interests may not coincide with the pool's interest. An investor-owned utility, for example, may have to balance its individual objective to preserve or enhance market position with the overall objectives and needs of the power pool.
- There may be a reluctance to coordinate with competitors. Some utilities may have more to gain than others from a cooperative undertaking. As a consequence of a pooling arrangement, competitive positions among the participants could undergo relative shifts.
- A long lead time is usually required to develop the pool mechanism. The history of the proposed Cactus Power Pool in the Arizona-New Mexico Power Area is a case in point. Despite considerable effort on the part of the participating utilities, negotiations to formulate a pool extended from August 1974 to January 1980, at which time they were terminated. (See Chapter 5 for further discussion of the Cactus Power Pool.)
- Compromise decisions may not always be optimum decisions.
- Decisionmaking by committee is time consuming.
- Increased overhead costs are required to support pool management and engineering committees. The need for separate management and technical support for a pool is dependent on the level and degree of coordination desired and the complexity of the arrangement. Increased overhead costs will diminish the benefits expected from the proposed arrangement.
- No universally accepted formula for allocating generation and transmission responsibilities and pool costs exists among participants. When operating in isolation, a utility's obligation to provide its power supply requirements reliably and economically is well established. When operating in a pool, a utility's obligation remains, but determining specific construction responsibilities becomes more difficult. Negotiations to resolve these aspects of pooling can be complex and lengthy.

As a general observation of the task force, good planning and operating coordination both exist in the Western Region, though they exist through a multiplicity of lower level coordinating arrangements. The current principal impediment to increased

regional coordination lies, therefore, in identifying additional benefits with sufficient certainty to justify the substantial expenditures required to realize the benefits. If the economics of increased coordination justify new facilities, then the potential exists for regulation to become the principal impediment.[2] The more significant regulatory impediments identified by the task force are the following:

1. The uncertainty of regulation, which impairs the ability of pooling participants to proceed with needed bulk facilities.
2. The attitude of individual States, which discourages out-of-State utilities from participating in jointly sponsored generation and transmission projects.
3. Regulatory action or inaction and the administration of environmental laws that result in facility cancellations and delays.

Examples to illustrate how economic regulation has impaired the financial ability of utilities to proceed with needed bulk power facilities are numerous. The current financial contraints within Public Sevice Company of Colorado (PSC), which has necessitated a substantial cutback in PSC's construction program, might be cited as typical. Hardest hit by the cutback was PSC's powerplant construction activity. PSC will experience at least a 1-year delay in completing the 500-MW Pawnee coal-fired plant and further delay in plans to build a 1000-MW coal-fired plant in southeast Colorado during the mid-1980's. Delay of Pawnee to year end 1981 will increase the overall plant cost by approximately 8 percent--an added financial burden for the comnpany and its customers in the long term, although short-term cash flow problems are somewhat relieved.

Consequence of the forced delay in Pawnee and southeast Colorado plants has required PSC to take a close look at its supply of electric energy and to assess system reliability. Additional purchases of power and energy will be required to offset the delays in new capacity additions. These purchases will be an added cost to the company and will utilize the already small surplus transmission capacity normally reserved for emergency situations. The overall results, while lessening the short-term cash flow problems, may well reduce the system reliability, cause forced load curtailment, and add to future financial burdens of the company and its customers.

As noted in number 2 above, one of the major themes articulated by the task force was the primary concern of the individual States

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[2]An opinion expressed by some of the task force members was that the discussion on regulatory impediments and recommended corrective legislation was well presented in the National Power Grid Study, Volume II, Chapter 12, September 1979, DOE/ERA-0056-2.

for their own residents. Some expression of this attitude is seen in the Montana Public Service Commission's statement of philosophy in the previous chapter. Although this may be temporary, the adverse effect on interstate coordination is nonetheless real. Some task force members also cite what they term to be the California Energy Commission's "no powerplant" policy as an expression of this attitude. They say that for several years the California Energy Commission has not approved construction of a major powerplant to meet needs within California, and as a consequence, the EHV transmission system has been stressed in ways that were not contemplated in original operating plans and facility design. Continuation of the California Energy Commission's "no powerplant" policy is, in the opinion of these members, an impediment to further utility integration until such time as additional generation is identified and EHV transmission is constructed to meet the import needs of California.[3]

To illustrate how the three significant impediments previously listed act together to impede coordinated and joint actions, a chronology of events in the construction of a jointly owned unit has been provided. In the illustration, impacts from construction delays were realized by six utilities in eight States. The current estimated cost for completion in 1983-84 is approximately $1 billion over the original estimate for 1978-79 completion, of which about 75

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[3]One task force member does not agree that this discussion properly characterizes the California Energy Commission's powerplant siting policy. In support of his contrary position he offers the following statement, quoted from the CEC's 1979 Biennial Report:

> The California Energy Commission's preferred energy future relies, in the short term, on conventional energy sources but places conservation and the development of renewable energy resources, such as solar and geothermal energy, cogeneration, biomass, and wind, as sources favored for the future. Alternate energy sources cannot totally displace conventional energy sources in the near future. Even a policy to accelerate the deployment of alternatives will leave the state dependent on conventional energy sources for over half of our energy needs in the year 2000. For example, California will still have to build at least two new coal plants by 1991; one in Northern California and another in Southern California. One or two additional coal plants may be needed unless the state makes a maximum commitment to cogeneration, conservation, and renewable energy sources, and begins to develop clean-burning synthetic fuels such as methanol and synthetic gas from coal.

percent is directly related to escalation and increased governmental regulation.

In Montana, Colstrip Units 3 and 4, coal-fired units of 700-MW capacity each, were planned jointly by the following six utilities starting in 1971.

- The Montana Power Co.
- Puget Sound Power & Light Co.
- Portland General Electric Co.
- The Washington Water Power Co.
- Pacific Power & Light Co.
- Basin Electric Power Cooperative (Agent for Central Montana G&T and Upper Missouri G&T)

An application for Colstrip 3 and 4 was filed under the Montana Utility Siting Act in June 1973. Originally, onsite physical construction for Colstrip 3 and 4 was to commence in May 1974, and the units were to be in operation in 1978 and 1979. Because of administrative and judicial delays, however, Colstrip 3 and 4 cannot now be completed until 1983 and 1984 at the earliest. Set forth below are some of the key dates in the history of Colstrip 3 and 4:

March 1973: Montana Utility Siting Act (proclaimed as "onestop" permitting statute) becomes law.

> During this transition from conventional to alternative technologies, California is not simply abandoning coal, oil, and gas as energy sources. In fact, they are part of a mixed strategy which also develops alternative energy sources to guarantee uninterrupted energy supplies in the future. This strategy foresees a need to build several base load power plants while expediting the development of cogeneration, geothermal, repowering, wind, and biomass facilities.
>
> The Energy Commission recognizes that the revolutionary changes in energy policy that will occur as we move from conventional to alternative sources of energy will cause anguish for some individuals. In fact, these policy changes are so fundamental that some public and private institutions now responsible for the development and implementation of energy policies will be forced to change in the process. The Commission admits that its proposed energy strategy is neither certain nor easy. It will involve changes in the way we view energy and in the way utilities view themselves. In the long run, California's emphasis on conservation and renewable energy sources will promote economic stability during the transition from conventional energy sources to a sustainable energy future.

June 1973:	Montana Power and associated utilities file application with Montana Department of Natural Resources & Conservation for Colstrip 3 and 4; pay filing fee of $1.232 million.
June 1973:	Department of Natural Resources begins its review of project proposal, setting in motion the 600 days allowed for review under the Utility Siting Act.
March 1974:	Bureau of Land Management (BLM) begins Federal Environmental Impact Statement (EIS) review after decision is made not to prepare a joint Federal-State EIS.
May 1974:	Start of Colstrip construction is scheduled so the units could become operational in 1978 and 1979, and applicants proceed to make commitments for equipment and facilities.
November 1974:	Federal EIS review is halted pending decision anticipated by State of Montana; BLM demands payment of $98,800 from applicants for 8 months of review.
November 1974:	U.S. Environmental Protection Agency (EPA) issues regulations for prevention of significant deterioration, applicable to sources that had not commenced construction prior to June 1, 1975.
November 1974:	Department of Natural Resources issues adverse report on Colstrip project after 600 days of review; review period produced 19 public hearings and six-volume, 3000-page EIS.
May 1975:	Board of Natural Resources & Conservation begins its hearings on Colstrip project after five delays as a result of litigation and requests for continuations. Hearing recessed for Board of Health hearings, which commenced in June 1975, and culminated in Board of Health conditioned certification in November 1975.
August 1975:	Region VIII of EPA indicates the Colstrip project had commenced construction as provided in PSD regulations and suggests that applicants request written ruling to confirm this position.

February 1976:	Applicants request ruling from EPA that the Colstrip units had commenced construction.
July 1976:	Applicants apply to EPA for preconstruction permit, reserving right to challenge the legality of the PSD regulations and their applicability to Colstrip.
July 1976:	Board of Natural Resources, after more than 1 year of hearings, issues certificate of environment compatibility and public need.
August 1976:	Northern Plains Resource Council and Northern Cheyenne Indian Tribe file petition for judicial review, seeking to reverse Board of Natural Resources.
September 1976:	EPA announces that Colstrip units would be within Class II air quality standards, but that a permit could not be issued because the Northern Cheyenne Indians were considering a proposal to redesignate their reservation as Class I.
October 1976:	EPA issues final ruling that Colstrip units had not commenced construction prior to June 1, 1975, and so were subject to PSD regulations.
October 1976:	Applicants file suit in U.S. District Court, seeking declaratory judgment that the units were not subject to PSD regulations.
December 1976:	EPA advises applicants that it had changed its definition of "commenced to construct" and that Colstrip units did not qualify.
January 1977:	U.S. District Court grants declaratory judgment that Colstrip units had commenced construction prior to June 1, 1975, and were exempt from EPA review and approval under PSD regulations.
March 1977:	Northern Cheyenne Indian Tribe applies to EPA for Class I designation of their reservation under PSD regulations.
May 1977:	Federal Court judgment is appealed to U.S. Circuit Court of Appeals by EPA, Northern

	Plains Resource Council, and Northern Cheyenne Indian Tribe.
June 1977:	EPA promulgates PSD rules under 1977 Clean Air Act Amendments.
August 1977:	Northern Cheyenne Indian Tribe receives Class I designation from EPA.
August 1977:	Congress passes 1977 Clean Air Act Amendments with new PSD statutory framework.
October 1977:	EPA orders construction of Colstrip units halted pending receipt of construction permits from Montana Board of Health and EPA.
January 1978:	Montana Department of Health approves conditional construction permit for Colstrip units.
January 1978:	EPA announces its intention to grant a construction permit for units after concluding they would be able to meet Federal Class I air quality standards on the Indian reservation.
February 1978:	Department of Health permit decisions are appealed by Northern Plains Resource Council to Board of Health.
February 1978:	Environmental Defense Fund (EDF) files suit in U.S. District Court in Washington, D.C., seeking to restrain EPA from issuing any permits for any source unless it was able to meet requirements of 1977 amendments to Clean Air Act; Colstrip units affected by action.
February 1978:	EPA advises applicants that, except for EDF action, a construction permit would have been processed for Colstrip units prior to March 1, 1978, so that they would be reviewed on basis of regulations in effect prior to that date.
March 1978:	State District Court in Helena, Montana, on procedural grounds, reverses 1976 decision of Board of Natural Resources and enjoins construction of Colstrip units; applicants seek review of District Court order by Montana Supreme Court.

March 1978:	U.S. Circuit Court of Appeals dismisses EDF action against EPA.
April 1978:	Board of Health affirms Department of Health's decision approving construction permit.
April 1978:	Supreme Court stays State District Court order enjoining Colstrip construction and orders expedited handling of the appeal.
May 1978:	Northern Plains Resource Council appeals to Supreme Court the Department of Health's granting of the construction permit.
June 1978:	EPA denies PSD permits for Colstrip 3 and 4.
June 1978:	Applicant's file, in the Ninth Circuit Court of Appeals, motion for stay and injunction and for expedited consideration of Federal District Court ruling that Units 3 and 4 were exempt from original PSD regulations. (Motion later denied.)
August 1978:	Applicants seek reconsideration within EPA of its decision denying PSD permit.
August 1978:	Applicants appeal to Ninth Circuit Court of Appeals the EPA denial of PSD permit and seek expedited consideration of the matter.
October 1978:	Oral argument held before the Montana Supreme Court on the appeal of the March 1978, State District Court reversal of the 1976 Board of Natural Resources decision.
November 1978:	Northern Plains Resource Council files a second and separate appeal in Rosebud County over the Department and Board of Health issuance of Clean Air Act construction permits in April 1978.
December 1978:	Applicants file opening brief in Ninth Circuit Court on EPA's denial of a PSD permit.
January 1979:	Circuit Court of Appeals sets oral argument for February 7, 1979, on the PSD "Grandfather" case.
January 1979:	Applicants preparing amendment to the July 1, 1976, application for a PSD permit, based on

	use of dolomitic lime for SO_2 removal of up to 96-98 percent.
January 1979:	Federal Draft Environmental Impact Statement on 500-kV transmission line is published.
January 1979:	Rep. Conroy, joined by 71 cosponsors, introduces legislation in Montana House of Representatives to preclude the possibility of further court proceedings on Colstrip 3 and 4 units pursuant to the Montana Siting Act.
February 1979:	Oral argument heard in Circuit Court of Appeals on PSD "Grandfather" case.
February 1979:	Amendment to July 1, 1976, application for a PSD permit filed with the EPA--Denver.
February 1979:	Update Board of Natural Resources on scrubber improvements by dolomitic lime system.
February 1979:	HB 452 exempting Colstrip Units 3 and 4 from further Montana legal action passed Montana House of Representatives, 53-47. Senate committee has bill and will act in 1 to 2 weeks. Senate passed amended version on first reading--presently back in committee.
February 1979:	EPA submitted schedule for processing amended application.
March 1979:	EPA notified us the amended application was deficient and requested additional information.
March 1979:	Above requested information submitted to EPA in a meeting in Denver. EPA indicated they wanted to stay on schedule and that information was adequate.
April 1979:	Notified in letter from N. A. Huey that the EPA considered the amended application complete.
April 1979:	HB 452 passed by senate and sent to Governor for signature. He must act by April 10.
April 1979:	Montana Supreme Court rules on appeal of District Court reversal of Board of Natural Resources decision--no further hearings by BNR

	or Department of Health are required as procedure was proper and information submitted was adequate. Court also requested BNR to come up with new findings and submit them to the court within 90 days. 1. Regarding the type of coal used (Makay vs. Rosebud), and which would cause the least environmental impact. 2. Whether it is better for minemouth location or shipping the coal to other sites--this from an environmental viewpoint. 3. The route of the 450-mile, 500-kV transmission line.
April 1979:	House of Representatives did not override Governor's veto.
April 1979:	EPA issues public notice of intent to issue permit.
May 1979:	Public hearings on above, May 22, in Helena; May 23, in Colstrip; and May 24, in Lame Deer.
May 1979:	Public comment period for EPA permit, which was originally scheduled to close on May 25, 1979, was extended to June 25, 1979.
June 1979:	Board of Natural Resources forwarded corrected "Findings of Facts and Conclusions to Montana Supreme Court."
June 1979:	Applicant filed petition with Montana Supreme Court asking they vacate their order suspending the certificate.
June 1979:	Applicant, Northern Cheyenne, and NPRC met in Denver with EPA to discuss issues relating to the permit.
June 1979:	Public comment period on EPA permit extended by EPA from June 25 to June 27, 1979. Then on June 27, the public comment period was closed.
June 1979:	Applicant argued petition before Montana Supreme Court.
June 1979:	Montana Supreme Court issued order requiring NPRC and others to file written briefs within

	10 days, and gave utilities and BNR 10 days to reply. Also set oral arguments on findings and briefs for July 20, 1979.
July 1979:	Argument before Montana Supreme Court regarding Board of Natural Resources Findings of Fact and Conclusions of Law submitted in June 1979.
July 16 1979:	Circuit Court of Appeals for the Ninth Circuit issued decision, which held that Colstrip Units 3 and 4 had not "commenced construction" within the meaning of the PSD Regulations and the Clean Air Act Amendments.
July 1979:	EPA sets schedule for 164(e) negotiations regarding PSD Permit.
September 5-7 1979:	EPA holds section 164(e) conference.
September 11 1979:	EPA issues PSD Permit.
September 17 1979:	Montana Supreme Court reinstates BNR Permit.
September 20 1979:	Excavation resumed at jobsite.

Despite the many impediments, benefits from increased regional coordination are substantial enough that efforts in the region are continuing. Task force members recognize that these efforts can be enhanced by better coordination and cooperation among utilities and by developing better ways to evaluate the real long-term incremental benefits of power pooling. In addition, other actions needed to enhance power pooling in the Western Region are the following:

- Institute an effective program to better inform elected officials, regulatory agencies, and the public as to the salient facts of regional bulk power supply
- Encourage State regulators to meet on a regular basis with regulators in other States to discuss and to address, to the extent possible, bulk power facilities siting issues and regulatory impediments.
- Encourage States, where regulation of the utility industry is dispersed among several single-purpose agencies, to review lines of communication between those agencies to ensure that effective communication is being maintained.
- Encourage Federal regulators to facilitate the timely construction of bulk power facilities.

- Encourage State regulators to provide a reasonable utility rate base and return necessary to support the construction of regional bulk power facilities and further integration.[4]

[4]In the view of task force members representing State regulators, regulation of the rate base and rate of return has not been an unreasonable impediment to the construction of needed regional bulk power supply facilities.

CHAPTER 9
REGIONAL OPPORTUNITIES FOR INCREASED COORDINATION

INTRODUCTION

The outlook for benefits from increasing the coordination within subregions has been discussed in the respective chapters for the Northwest Power Area, the Rocky Mountain Power Area, the Arizona-New Mexico Power Area, and the California-Nevada Power Area. Additionally, there are opportunities within the Western Region requiring even broader involvement than the individual subregions. The conceptual planning and coordination involved in the construction of the Pacific Northwest-Southwest Intertie is one clear example of some of the innovations that provided benefits in the past. The following discussion provides examples of further opportunities for increased coordination in the Western Region.

ADDITIONAL INTERREGIONAL INTERTIES

PRESENT SITUATION

The Pacific Intertie system consists of two 500-kV a-c lines and an 800-kV d-c line from The Dalles Dam to southern California, which have been in service since 1968, 1969, and 1970, respectively. These lines provide 3940 MW of transmission capacity for the interchange of power and energy between the Pacific Northwest and the Pacific Southwest.

OPPORTUNITIES AND IMPEDIMENTS

Three proposals for supplementing the present intertie capability are being studied. One proposal is part of the original intertie system approved by Congress in 1964 and envisions a second d-c line to the Phoenix area. Also under study are a third a-c line to northern California and an increase in the transmission capacity of the existing d-c line.

In the building of any structure, environmental impacts must be assessed. A fundamental environmental concern is whether or not a facility is needed, and if it is, whether the best alternative is proposed. Not only the impacts of the structures must be assessed, but also the impacts resulting from the operations as a result of

the contracts entered into. For example, some of the concerns that would need to be addressed include how changed reservoir and river operations would affect recreation, navigation, and the anadromous fishery. These and other environmentally oriented questions would need detailed study, requiring considerable time.

Uncertainties in estimating generating resource delays in the Pacific Northwest and in identifying specific new generating resources in adjacent areas, result in an uncertainty of firm resource plans for the 1990's. This uncertainty complicates the analysis of future transactions on the interties and makes planning and benefit and cost analysis of new interties difficult.

Second d-c Line

The northern terminal of this proposed intertie would be at the site of the existing terminal at Celilo near The Dalles in Oregon. The proposed southern terminal would be at Phoenix, Arizona, with a possible intermediate terminal at Mead, Nevada. The total length of the line would be 1054 miles. The intertie would be a $\pm$ 500-kV bipolar overhead transmission line with an ultimate capacity of 2200 MW. The total cost of single-stage development of such a system would be about $505 million, excluding interest during construction. Representatives of BPA, WAPA, and Pacific Northwest and Pacific Southwest utilities met in July 1978 to discuss the intertie and to outline a plan for further studies. Some alternatives to this proposed d-c line have been suggested, but definitive studies of alternatives have not been made pending further analysis of the benefits and costs of this additional interregional transmission capacity.

The Third a-c Line

Plans within the Pacific Northwest call for construction of a major portion of any third a-c intertie by the Bonneville Power Administration (BPA) and Pacific Power & Light Co. (PP&L). This would include additional development of the Buckley Switching Station in North Central Oregon, addition of series capacitors in the Buckley-Summer Lake 500-kV line, changes in series compensation in the existing intertie lines, and possible increased development of the Summer Lake Switching Station in South Central Oregon. The Summer Lake-Malin 500-kV line is a portion of PP&L's Midpoint-Malin 500-kV line, which is now under construction. Multiple use of these facilities to serve Bend and southwest Oregon loads would provide about 1500 MW of capacity for the third intertie. The three a-c interties together would have a capacity of about 4000 to 4500 MW. Similarly, third intertie line additions in California would be required to increase the capacity of Pacific Gas and Electric Company's system in California. The third a-c line is being

evaluated for possible sale of Pacific Northwest surplus secondary energy, capacity exchanges, and the pooling of reserves between the two areas. A rigorous evaluation of optimum transmission system plans, benefits and costs, and environmental impacts of a third a-c line has not yet been completed.

Increased Capability of Existing d-c Line

Investigations by a BPA-Utility Task Force indicate that it is technically feasible to raise the operating voltage of the existing d-c line from ± 400 kV to ± 500 kV, thereby increasing the capability of the line by 360 MW. Costs are estimated to be approximately $76 million (1978 dollars), of which approximately one-half of the total would be incurred by BPA.

The capacity of the existing d-c line has recently been increased from 1440 to 1600 MW by increasing the current rating from 1800 to 2000 A. This is a test to determine the effects of line operation at the increased current. If the 2000 A rating is made permanent, upgrading the operating voltage from ± 400 kV to ± 500 kV would increase the capacity another 400 MW to 2000 MW. Both the voltage increase and the capacity increase are budget items in BPA's FY 1980 program.

Of the three proposals to increase capability of the intertie, interest centers on "voltage upgrading" of the d-c line first. Preliminary estimates indicate that upgrading the d-c line can be economically justified solely because of increased efficiency at the higher voltage and increased sales of Pacific Northwest surplus energy.

A meeting of BPA representatives and Pacific Southwest utilities was held on November 16, 1978, at which time BPA presented a preliminary analysis indicating a benefit and cost ratio of about two for the voltage upgrade. The participants established two task forces: an Engineering Task Force and a Power Supply Task Force, to review and finalize the preliminary BPA Feasibility Study.

A final report indicating feasibility was completed on January 26, 1979.

UNITED STATES-CANADIAN TRANSACTIONS

PRESENT SITUATION

In the Western Region, the only Canada-United States interconnections are between British Columbia and Washington. British Columbia Hydro and Power Authority and Bonneville Power Administration are connected by two 500-kV circuits at Blaine, Washington and a 230-kV circuit at Boundary, Washington. Also, Cominco Ltd. and BPA are connected by a 230-kV circuit (operated by

West Kootenay Power and Light Company) at Boundary, Washington. The types of transactions that have occurred historically between Canada and the United States at the international interconnections are short-term firm sales, interruptible sales, emergency exchanges, storage of energy in reservoirs, treaty deliveries, and wheeled power. The magnitude of transactions that involved delivery from Canada to the United States from 1975 through July of 1978 was about 16,000 GWh. Transactions involving delivery from the United States to Canada during that same period amounted to about 6000 GWh.

OPPORTUNITIES AND IMPEDIMENTS

There are no firm or tentative plans for additional interconnection capacity between those parts of Canada and the United States encompassing British Columbia and the western United States. However, the potential for increasing advantageous international power exchanges, especially from Canada to the United States, does exist because of planned expansion of transmission and generating facilities in British Columbia and Alberta.

No significant quantities of firm energy from British Columbia would be available before 1988. After 1987, however, new generating facilities might be developed ahead of British Columbia's domestic requirements. After 1991, it is possible that some hydroelectric projects on northern B.C. rivers such as the Iskut, Stikine, and Liard could be developed to provide part of their energy output for an export market. Potential maximum amounts available for export could be in the range of 300 average MW per year up to 1990, possibly rising to 1000-1500 average MW by 1994.

By 1984, a 500-kV British Columbia-Alberta interconnection will exist, permitting transmission for several years of an anticipated Alberta surplus of about 2000 GWh per year. The major portion of this energy would be available only during offpeak hours, but would be relatively firm. Beyond 1986 it would be possible to advance coal-fired thermal generation facilities ahead of Alberta's domestic requirements. Such capacity would be in unit sizes of 375 MW with 80-percent annual capacity factors. This leads to the possible import from Canada of about 2000 MW of coal by the early 1990's. Two additional hydroelectric projects, having a potential of 490 average megawatts and 910 average megawatts, are also being considered for development in the early 1990's. It might be possible to develop these resources ahead of the time they are required in Alberta and to make the energy available for export.

Following are important obstacles to increased United States-Canadian interchanges:

1. Hearings in Canada and the United States have revealed considerable opposition to the construction of facilities for the purpose of exporting the energy.

2. Such construction may conflict with environmental and land use values.
3. Many apparently mutually beneficial arrangements are inhibited by the rate requirements of the Canadian National Energy Board. This agency insists that the prices for Canadian power charged to U.S. purchasers not be materially less than the cheapest alternative power available from U. S. sources.
4. Possible jurisdictional conflicts may develop in Canada regarding development of certain of the projects mentioned above.
5. Other projects involve U.S. waters not under International Joint Commission jurisdiction. Treaties would be required for power development of such waters.
6. Transmission capacity for wheeling Canadian energy over BPA lines to Southwest markets may be reduced to about 1500 MW because of the presence of large thermal generators in the Pacific Northwest. A similar problem may arise with thermal development in Alberta.

STATUS

A study group consisting of representatives of Alberta, Interconnected System, B.C. Hydro, and BPA was formed in the spring of 1979 to identify the availability of surplus energy in their respective regions, to determine the usability of that energy, and to identify transmission constraints that limit the ability to market that energy. A progress report was published in April 1980. The conclusions and recommendations from this report are as follows:

Conclusions and Recommendations of Canadian/U.S. Interchange Capability Study

From this study it can be concluded that:

1. Ninety-five percent of the available surplus energy in Alberta, British Columbia, and the United States Pacific Northwest systems can be delivered to markets with the existing/planned transmission system.
2. Transmission constraints preclude the utilization of the remaining 5 percent of available surplus energy. The constraints occur in the:
   a. internal transmission system in Alberta and the Alberta/British Columbia 500-kV interconnection;
   b. interconnection between British Columbia and BPA;
   c. intertie from the United States Pacific Northwest to the Pacific Southwest.
3. The major transmission limitation occurs between the U.S. Pacific Northwest and Southwest. The capability of the PNW-PSW

intertie precludes the displacement of PSW oil-fired generation in the amounts of 534 average annual megawatts in 1984-85, and 888 average annual megawatts in 1989-90. These quantities are greater than the unusable energy referred to in item 2 above, by the amount of the PNW coal and nuclear generation available to displace PSW oil. The internal transmission constraint in the Alberta Interconnected System also significantly limits the marketability of surplus coal-fired energy. The limitation in marketing surplus energy due to these two constraints increases with time.

4. The scheduling capacity of 2000 MW between British Columbia and BPA will not impose a significant limitation on the marketability of surplus energy in the near future. This situation could change if the Skagit nuclear plant is constructed at Sedro Woolley, Washington, by the late 1980's. With Skagit's associated transmission as presently proposed, the scheduling capacity would be reduced to 1000-1500 MW, depending on loading and generation patterns.
5. The British Columbia-BPA transfer capability could impose a significant limitation if generation additions are advanced to increase the surplus energy available from Canada. This situation has not been analyzed in this study.

The following is recommended by the study group:

1. Use the data in this study to identify transmission limitations--including estimates of the level and duration of peak-line loadings--in the interconnections between the AIS, BCH, WGA, and PSW systems to determine the economic feasibility of strengthening those interconnections.
2. Identify additional amounts of surplus energy that could be available by accelerated generation schedules.
3. Determine the usability of any additional amounts of surplus energy from those accelerated generation schedules and analyze transmission limitations as in 1 above.

INCREASED COORDINATION FOR ENERGY CONSERVATION

Load and resource data issued annually by WSCC, coupled with the regionwide communication network operated by WSCC, indirectly assist utilities in identifying opportunities for joint ownership arrangements, short-term capacity exchanges, and economy energy transfers.

To further facilitate economy energy transfers and energy conservation, WSCC began an oil conservation program in September 1979 and will be implementing an energy brokering system on a trial basis beginning in September 1980. Details of these activities follow.

OIL CONSERVATION

Within the WSCC Region, 31 individual utilities are providing data for each hour of every day in support of WSCC's oil conservation survey effort to accomplish the following:

1. Ensure that oil burn requirements within the region are being minimized.
2. Document WSCC's continuing performance in conserving oil by maximizing the use of non-oil-fired generation.
3. Identify the impediments that prevent additional oil conservation.

The most significant factor limiting oil displacement within the region is an insufficient amount of non-oil-fired generation available to displace all of the displaceable oil-fired generation. Therefore, if the region's non-oil-fired generation is being maximized, essentially nothing could significantly reduce the region's oil burn requirements short of curtailing customer load. With this in mind, WSCC established the following objectives:

1. Maximize its non-oil-fired generation such that it displaces as much oil-fired generation as possible.
2. Evaluate the region's oil conservaton effectiveness on the basis of using all of the available non-oil-fired generation in the region.

Based on survey results to date, WSCC's daily effectiveness in utilizing its non-oil-fired generation has ranged from 96 to 99 percent.

ENERGY BROKERING SYSTEM

The benefits of regional coordination (planning and operating) are well recognized within WSCC. For example, the utilities have for years recognized the potential savings associated with maximizing the region's hydroelectric and coal-fired energy to minimize oil- and gas-fired generation. Recently, the WSCC member systems undertook a new activity to reasonably ensure that the system dispatchers have the ability to efficiently and conveniently take advantage of essentially every opportunity to minimize operating costs. Coordinated by WSCC, this new activity is the implementation of an "energy brokering system." The system, which will supplement current scheduling practices, will function as an effective communication system to:

1. Maximize the hourly savings of the participants through the use of an automated system.

2. Ensure that essentially all potential money saving economy interchanges are consummated.

The system, which will encompass the four diverse subregions of WSCC, is being implemented on a trial basis. The system became operational in September 1980.

EXPANDED GEOGRAPHIC AREA GENERATION AND TRANSMISSION PLANNING

NORTHWEST POWER AREA

Areawide generation and transmission planning now comprises the geographic area included in the West Group Area of the Northwest Power Area. This area consists of the entire State of Washington, the Panhandle of Idaho, Oregon (except for the southeastern portion), part of northern California, the BPA and PP&L service areas in Montana, and the BPA loads and WAPA resources in southern Idaho.

The Intercompany Pool also makes planning studies for the investor-owned utilities located in Oregon, Washington, Idaho, Montana, Utah, most of Wyoming, and northern California.

Opportunities and Impediments

Potential benefits from combining West Group Area planning with adjacent areas include the following:

- Load diversity
- Climatic and hydrologic diversity, which would affect both loads and resources
- The lesser amount of generating reserve required for a combined system than for separate systems
- Opportunities to optimize transmission requirements
- Interregional assistance in the event of disaster affecting electric supply

The task of data gathering and processing under present planning procedures is considerable. The increased data load due to expanded regional planning would be an additional burden.

Institutional constraints could present several obstacles. In the Pacific Northwest, where long-range planning is now performed voluntarily through the Pacific Northwest Utilities Conference Committee (PNUCC), operational planning is achieved contractually through the PNW Coordination Agreement. Changes in planning procedures would have to be accompanied by contractual changes, or be seriously hampered by existing contractual obligations.

A greater degree of expanded geographic area planning could be implemented through WSCC. However, WSCC's present objectives are

limited to concern for adequacy and reliability, and not to whether or not the region is planned or operated in the optimum economic fashion.[1] Additionally, there may be a diversity of interest between the West Group Area and neighboring systems, for example, different reliability criteria, different planning procedures.

The limited capacities of interconnections with neighboring systems may be an additional obstacle to expanded regional planning. Interconnections may have to be strengthened to permit diversity exchanges, economy energy exchanges, economic dispatch, and reserve backup.

Last, the complications of applying the measuring and sharing of benefits of one-owner planning concepts to a pluralistic electric system present a major institutional barrier that frequently results in less than optimally planned facilities.

Status

In the spring of 1979, BPA and WAPA (upper Missouri) representatives discussed strengthening the tie between the two systems. Because BPA will be constructing transmission to integrate part of the Colstrip, Montana generation into the West Group Area, and because WAPA was studying additional transmission to connect upper Missouri hydroelectric with Colorado and Nebraska loads, it had been speculated that it might be beneficial to extend the Colstrip transmission east to strengthen the BPA-WAPA interconnection. Preliminary estimates of benefits were not large enough to warrant further study.

The Pacific Northwest Utilities Conference Committee (PNUCC) conducted some preliminary studies related to combining West Group and East Group planning. The East Group members are Idaho Power Co., Montana Power Co., and Utah Power and Light Co.; they have accepted membership in the PNUCC. A further study effort has been defined, and a joint planning report is scheduled to start in 1980 beginning with the 1980-81 operating year.

ROCKY MOUNTAIN POWER AREA

Significant transmission and reliability concerns in the Rocky Mountain Power (RMP) Area are related to the following regional factors:

- Development of coal-fired generation in Wyoming and Montana and the associated transmission to load centers in the Northwest Power Area

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[1]U.S. Department of Energy, National Power Grid Study, Volume II, September 1977, Page 253.

- Transmission limitation between the RMP Area and the Arizona-New Mexico Power Area
- Effect of clockwise loop flows on the bulk power system of the RMP Area

Opportunities for Improvement

Economic and reliability penalties incurred because of inadvertent power flows caused by coal-fired generation in Wyoming and Montana being transmitted to the Northwest Power Area may be reduced by the completion of additional EHV (500 kV) transmission lines planned for construction between the coal-fired plants and the load centers. However, an organizational mechanism is required to ensure that future coal-fired generating stations in this area be provided with sufficient transmission capability to mitigate the adverse impact of inadvertent flows on other WSCC utilities.

Transmission limitations between the RMP Area and the Arizona-New Mexico Power Area prevent increased utilization of offpeak coal-fired generation in the RMP Area for replacing oil-fired generation in the Arizona-New Mexico Power Area and the California-Nevada Power Area, and for any seasonal diversity that is not being exploited. Utilities in both areas currently are studying the addition of stronger transmission ties to increase both transfer capability and reliability.

Because of the prevailing clockwise loop flows in the WSCC transmission network, a component of the large thermal generation base in the Rocky Mountain Power Area, which is scheduled to serve firm loads in the Northwest Power Area, actually flows south around the WSCC loop. Increasing clockwise loop flows will continue to adversely affect the transmission system in the southern portion of the RMP Area. Economy energy transfers and energy transactions displacing oil will continue to be eliminated by loop flows. Clearly, extraordinary measures must be initiated by WSCC utilities to solve the loop problem by a regional approach to planning, for purposes of economy and reliability. Joint planning to identify regional coordination opportunities may well result in a combination of EHV and d-c lines that would minimize growing clockwise loop flows.

APPENDIX A
ELECTRIC POWER CHARACTERISTICS
WESTERN REGION

Electric Power Characteristics
Northwest Power Area

Name of Utility	State	Code	Installed Capacity 1978 (MW)	Peakload 1978 (MW)	Major Interconnections[1]	Radial Interconnections	Purchases Power From
Western Region[2]			97,550	80,213 (non-coinc.)	BCHA,[3] WKPL,[4] MARCA[1]		
Northwest Power Area			37,439	30,369			
Bonneville Power Administr.-PNW	MT, OR WA, WY	BPA		9,409	USPN, USUC, USCE, BCHA, WPPSS, CHPD, DOPD, WKPL, IPC	Numerous	USPN, USUC, USCE, BCHA, PPL, PSPL, TCL
Bonneville Power Administr.-So.ID	ID	BPA		188	UPLC, GRPU, POPD, WAMP, PPL, LDWP, SCL, TCL, MPC, WWPC, PGE, PSPL, EWEB		WWPC, WPPSS, CHPD, DOPD GCPD, POPD SCL
Albion	ID					BPA	BPA
Bandon	OR					BPA	BPA
Benton County PUD	WA					BPA	BPA
Blaine	WA					BPA,PSPL	BPA
Bonners Ferry	ID		5	14		BPA	BPA
Burley	ID					BPA	BPA
Canby	OR					BPA, PGE	BPA
Cascade Locks	OR					BPA	BPA
Central Lincoln Co. PUD	OR					BPA	BPA
Centralia	WA		10	43		BPA, WWPC	BPA
Cheney	WA					BPA	BPA
Clallam Co. PUD	WA					BPA	BPA
Clark Co. PUD	WA				BPA	PPL	BPA
Clatskanie PUD	OR					BPA	BPA
Coulee Dam	WA					BPA, Ferry Co. PUD Nespelem Valley	BPA
Cowlitz County PUD	WA	COPD	70	498	BPA, PPL	BPA, Lewis Co. PUD	BPA, GCPD
Declo	ID					BPA	BPA
Drain	OR					BPA, PPL	BPA
Eatonville	WA					BPA	BPA
Ellensburg	WA					BPA, Kittitas Co.	BPA, PSPL
Ferry Co. PUD	WA					BPA, Coulee Dam	BPA, Coulee Dam
Fircrest	WA					BPA	BPA
Forest Grove	OR					BPA	BPA
Franklin Co. PUD	WA					BPA	BPA
Grays Harbor Co. PUD	WA	GHPD			BPA		BPA
Heyburn	ID					BPA	BPA
Idaho Falls	ID		8	98		BPA,UPLC, IPC	BPA
Kittitas Co. PUD	WA					BPA. GCPD, Ellensbg., PSPL	BPA, PSPL, GCPD
Klickitat Co. PUD	WA					BPA, PPL	BPA

Lewis Co. PUD	WA		BPA	BPA, PSPL	BPA, WPPSS, COPD
Mason Co. PUD No. 1	WA			BPA	BPA
Mason Co. PUD No. 3	WA			BPA	BPA
McCleary	WA			GHPD	BPA
McMinnville	OR			BPA	BPA
Milton	WA			BPA	BPA
Milton-Freewater	OR			BPA	BPA
Minidoka	ID			BPA	BPA
Monmouth	OR			BPA	BPA
Northern Wasco Co. PUD	OR			BPA	BPA
Okanogan Co. PUD	WA			BPA	BPA
Pacific Co. PUD	WA			BPA	BPA
Port Angeles	WA			BPA	BPA
Richland	WA			BPA	BPA
Rupert	ID			BPA, IPC	BPA
Skamania Co. PUD	WA			BPA	BPA
Snohomish Co. PUD	WA	SHPD	BPA, SCL, PSPL		BPA, WPPSS
Springfield	OR			BPA, PPL	BPA
Steilacoom	WA			BPA	BPA
Sumas	WA			BPA, PSPL	BPA
Tillamook PUD	OR			BPA, PPL	BPA
Vera Irrig. Dist. No. 15	WA			BPA	BPA
Wahkiakum Co. PUD	WA			BPA	BPA
Whatcom Co. PUD	WA			BPA	BPA
Alder Mutual Light Co.	WA			BPA	BPA
Benton Rural Elec. Assn.	WA			BPA, PPL, Benton Co. PUD	BPA
Big Bend Elec. Coop.	OR			BPA, GCPD, PPL, WWPC	BPA
Blachly-Lane Co. Coop.	OR			BPA	BPA
Central Elec. Coop.	OR			BPA	BPA
Clearwater Power Co.	ID, WA, OR			BPA, WWPC	BPA
Columbia Basin Elec. Coop.	OR			BPA	BPA
Columbia Power Coop.	OR			BPA, PPL	BPA
Columbia Rural Elec. Assn	WA, OR			BPA, PPL	BPA
Consumers Power Co.	OR			BPA, PPL	BPA
Coos-Curry Elec. Coop.	OR			BPA	BPA
Douglas Elec. Coop.	OR			BPA, PPL	BPA
East End Mutual Elec.	ID			BPA	BPA
Elmhurst Mutl. Power & Light Co.	WA			BPA, TCL	BPA
Fall River Elec. Coop.	ID, MT, WY				
Farmers Elec. Co.	ID			BPA	BPA
Flathead Elec. Coop.	MT			BPA	BPA
Glacier Elec. Coop.	MT			MPC, Canada	BPA, USLM
Harney Elec. Coop.	OR, NV			BPA	BPA
Hood River Elec. Coop.	OR			BPA, PPL	BPA
Idaho County L & P Coop.	ID			WWPC	BPA
Inland Power & Light Co.	WA, ID			BPA, POPD, WWPC	BPA, POPD
Kootenai Elec. Coop.	ID, WA			BPA, WWPC	BPA
Lakeview Light & Power	WA			BPA	BPA
Lane Elec. Coop.	OR			BPA, PPL	BPA
Lincoln Elec. Coop., Mont.	MT			BPA	BPA
Lincoln Elec. Coop., Wash.	WA			BPA, WWPC	BPA
Lost River	ID			UPLC	BPA

Electric Power Characteristics
Northwest Power Area (Continued)

Name of Utility	State	Code	Installed Capacity 1978 (MW)	Peakload 1978 (MW)	Major Interconnections[1]	Radial Interconnections	Purchases Power From
Lower Valley Power & Lt.	ID, WY	LOVP	2	76		BPA	BPA
Midstate Elec. Coop.	OR					BPA	BPA
Missoula Elec. Coop.	ID, MT					MPC	BPA, MPC
Nespelem Valley Elec. Coop.	WA					BPA, GCPD	BPA
Northern Lights	ID, MT					BPA, Canada, WWPC	BPA, MPC, WWPC
						MPC	
Ohop Mutual Light	WA					BPA	BPA
Okanogan Co. Elec. Coop.	WA					BPA	BPA
Orcas Power & Light	WA					BPA, PSPL	BPA
Parkland Light & Water Co.	WA					BPA	BPA
Peninsula Light Co.	WA					BPA	BPA
Prairie Power Coop.	ID				BPA, IPC	BPA	
Raft River Elec. Coop.	ID, NV, UT					MPC	BPA
Ravalli Co. Elec. Coop.	MT					BPA	BPA
Riverside Elec. Coop.	ID					BPA, IPC	BPA
Rural Electric Co.	ID					BPA	BPA
Salem Electric	OR					UPLC, Lost R.REA	BPA
Salmon River Elec. Coop.	ID					BPA	BPA
South Side Elec. Lines	ID					BPA, PSPL	BPA
Tanner Elec.	WA					BPA, PAPL	BPA,
Umatilla Elec. Coop., Assn	OR					BPA	BPA
Unity Light & Power	ID					BPA	BPA
USBIA-Wapato Irrig. Proj.	WA		4			MPC	BPA, MPC
Vigilante	ID, MT					BPA, PPL	BPA
Wasco Elec. Coop.	OR					BPA, IPC	BPA
Wells Rural Elec.	NV, UT					BPA, PPL, PGE	BPA
West Oregon Elec. Coop.	OR						
British Columbia Hydro & Pwr. Auth.[5]	B.C. Canada	BCHA	6,966[6]	4,919[6]	BPA[3], WKPL, Alcan Calgary Pwr.		
Bureau of Reclamation	ID, MT WA	USPN	5,096[7]		BPA		(None)
-Pacific Northwest	OR, UT, WA			412	BPA, WWPC, PSPL, DOPD		BPA, DOPD, WWPC
Chelan County PUD	WA	CHPD	1,682		BPA		(None)
Corps of Engineers	ID, MT, OR, WA	USCE	11,387[8]	120	BPA, CHPD	Waterville	BPA
Douglas County PUD	WA	DOPD	774			DOPD	DOPD
Waterville	WA			483	BPA		BPA, Lane Elec., Springfield
Eugene Waters & Elec. Board	OR	EWEB	188	257	BPA, WWPC, PPL	Kittitas Co. PUD Coop.	BPA, WWPC, WPPSS
Grant County PUD	WA	GCPD	1,620				

Idaho Power Co. -Main & Salmon Sys.	ID, OR, WY	IPC	1,412	1,853	BPA, WWPC, PPL, UPLC, MPC		BPA, UPLC, PPL
CP-National	OR		1	100			IPC
Weiser	ID				IPC		IPC
Montana Power Co.	MT, WY	MPC	1,431	1,152	BPA, WWPC, WAUM IPC, UPLC, USUM		BPA, UPLC IPC, WAUM
Beartooth Elec. Coop.	MT, WY					MPC	MPC
Big Flat Elec. Coop.	MT					MPC	MPC
Big Horn Elec. Coop.	MT, WY					MPC	MPC
Fergus Elec. Coop.	MT					MPC	MPC
Hill County Elec. Coop.	MT					MPC	MPC, WALM
Marias River Elec. Coop.	MT, Canada					MPC	MPC
Mid Yellowstone Elec. Coop.	MT					MPC	MPC
Park Elec. Coop.	MT					MPC	MPC, WALM
Sun River Elec. Coop.	MT					MPC	MPC, WALM
Valley County Elec. Coop.	MT					MPC	MPC
Yellowstone Valley Elec.	MT					MPC	MPC, WALM, CMGT
Montana Light & Power	MT		18	17	PPL		PPL
Pacific Power & Light Co.	ID, MIT, OR, WA, WY	PPL	4,812[9]	3,507[10]	BPA, PGE, IPC, WWPC MPC, PG&E, COPD, BHPL, CHPD, DOPD	WWPC, BPA	BPA, WWPC, PGE, MPC, IPC, BHPL DOPD, GRPU, CHPU, COPU
Pend Oreille County PUD	WA	POPD	61	30		BPA, Canada	BPA
Portland General Electric	OR	PGE	2,681	2,796	BPA, PPL		BPA, GRPU, CHPU, DOPD, SCL, TCL, WWPC, MPC, SCE, PSPL, IPC
Puget Sound Power & Light	MT, WA	PSPL	483	3,284	BPA, CHPD, SCL, TCL Snohomish Co. PUD, BCHA, MPC	Lewis Co. PUD	BPA, CHPD, MPC WWPC, PPL, IPC, WCHA
Des Moines, City of	WA					PSPL	PSPL
DuPont	WA					PSPL	PSPL
Oak Harbor	WA					PSPL	PSPL
Seattle City Light Dpt.	WA	SCL	1,307	1,592	BPA, PSPL		BPA, POPD, GRPU, PSPL, BCHA
Tacoma City Light	WA	TCL	660	825	BPA, PSPL	Ruston	BPA, GCPD
Ruston	WA					TCL	TCL
USBIA-Flathead Project	MT		1	47	BPA, MPC		BPA, MPC
Utah Power and Light Co.	ID, UT, WY	UPLC	2,736	2,102	IPC, PPL, BPA, MPC SPP		BPA, MPC, PPL IPC, SPP, WWPC SCE
Beaver	UT		7			UPLC	WAPA, ICPA
Blanding	UT					UPLC	UPLC
Bountiful	UT		8	31		UPLC	WA, ICPA
Bridger Valley	UT, WY					WAUC, MOLE	WAUC
Brigham	UT		2	12		UPLC	WAUC, UPLC
Dubois	ID					UPLC	UPLC
Ephraim	UT					UPLC	WAUC, ICPA
Fairview	UT					UPLC	WAUC, ICPA
Fillmore	UT					UPLC	WAUC, ICPA
Heber	UT		1	8		UPLC	WAUC, ICPA
Helper	UT					UPLC	UPLC
Holden	UT					UPLC	WAUC, ICPA
Hyrum	UT					UPLC	WAUC, ICPA
Kaysville	UT					UPLC	WAUC, ICPA
Lehi	UT					UPLC	WAUC, ICPA

Electric Power Characteristics
Northwest Power Area (Continued)

Name of Utility	State	Code	Installed Capacity 1978 (MW)	Peakload 1978 (MW)	Major Interconnections[1]	Radial Interconnections	Purchases Power From
Levan	UT					UPLC	WAUC
Logan	UT		9	29		UPLC	WAUC, ICPA
Manti	UT		1			UPLC	WAUC, ICPA
Mexican Hat	UT					UPLC	UPLC
Monroe	UT					UPLC	WAUC, ICPA
Monticello	UT					UPLC	UPLC
Moon Lake Elec.	CO, UT	MOLE	2	89	WAUC, UPLC		
Morgan	UT					UPLC	WAUC, ICPA
Mt. Pleasant	UT		1			UPLC	WAUC, ICPA
Murray	UT		9	42		UPLC	WAUC, ICPA, UPLC
Nephi	UT					UPLC	WAUC, ICPA
Oak City	UT					UPLC	WAUC, ICPA
Price	UT					UPLC	UPLC
Provo	UT		14	68		UPLC	WAUC, ICPA
Soda Springs	ID		1			UPLC	WAUC, ICPA
Spring City	UT					UPLC	WAUC, ICPA
Lincoln Service Corp.	WY					UPLC	UPLC
CP-National, Cedar City	UT	CPNL	16	40	UPLC, St. Geroge		WAUC, UPLC
Dixie-Excalante REA	AZ, UT					CPNL, Overton P.D.	WAUC
Enterprise	UT					CPNL	WAUC
Hurricane	UT					CPNL	WAUC
Paragonah	UT					Parowan	WAUC
Parowan	UT					CPNL	WAUC
St. George	UT		7	27	CPNL		WAUC
Flowell Electric Assn.	UT					UPLC	ICPA, WAUC, UPLC
Kanosh	UT					Flowell Elec. Assn.	ICPA, WAUC
Meadow	UT					Flowell Elec. Assn.	ICPA, WAUC
Garkane Power Assn.	AZ, UT	GAPA	4	26	UPLC, WAUC	CP-National (Kanab)	ICPA, WAUC, UPLC
CP-National (Kanab)	UT					GAPA	GAPA
So. Utah Valley Power Proj.	UT	SUVPP	2	34 est.		UPLC	WAUC, UPLC
Payson	UT					SUVPP	SUVPP
Salem	UT					SUVPP	SUVPP
Spanish Fork	UT					SUVPP	SUVPP
Weber Basin Water Cons. Dist.	UT		6			UPLC	UPLC
Washington Public Power Supply	WA	WAPS	870		BPA		(None)
Washington Water Power Co.	ID, MT, WA	WAWP	829	1,543	BPA, IPC, MPC, PAPL, CHPD, GCPD		BPA, PPL, BCHA, PSPL, IPC, MPC UPLC, CHPD, GCPD DOPD, SPOK
Chewelah	WA					WWPC	WWPC
Citizens Utilities, ID	ID					WWPC	WWPC
Modern Electric Water Co.	WA					WWPC	WWPC
Plummer	ID					WWPC	WWPC
Spokane	WA	SPOK	4	4		WWPC	WWPC

West Kootenay Power & Light[11]	B.C. Canada	WKPL	49[6]		BPA[4], BCHA		BCHA
Bureau of Reclamation (Water & Power Resources Service) - Upper Missouri Region	MT	USUM	50[12]		MPC		(None)
Western Area Power Administration - Upper Missouri Region	MT	WAUM		1	MPC		USUM
Tongue River	MT			10		WALM, MPC	Cent, MT G&T (WALM, MPC)

Electric Power Characteristics
Arizona-New Mexico Power Area

Name of Utility	State	Code	Installed Capacity 1978 (MW)	Peakload 1978 (MW)	Major Interconnections[1]	Radial Interconnections	Purchases Power From
Arizona-New Mexico Power Area			12,678	8,153			
Ajo Improvement Co.	AZ			21			Phelps Dodge
Arizona Elec. Power Coop.	AZ	AEPC	393	199	APS, SRP, WALC, TGE	Trico, DVEC, SSVE	APS, WALC
Duncan Valley Elec. Coop.	AZ, NM	DVEC				AEPC	AEPC
Graham County Elec. Coop.	AZ	GCEC				AEPC, Thatcher, Safford	AEPC
Safford	AZ		7	9		GCEC	AEPC, WALC
Sulphur Springs Valley Elec. Co.	AZ	SSVE				AEPC	AEPC
Thatcher	AZ					GCEC	AEPC
Trico Elec. Coop.	AZ					AEPC, TGE, Mexico	AEPC
Arizona Power Authority	AZ	APA			(None)	(None)	WALC, APS
Arizona Public Service Co.	AZ, NM	APS	4,214	2,435	WALC, WAUC, SRP TGE, SCE, LDWP, NEVP, AEPC	Mexico	WALS, SRP, SCE, Yuma Axis P.
Citizens Ut.-Lake Havasu	AZ	CUCLH				WALC	WALC
Citizens Ut.-Mohave Div.	AZ	CUCMO				WALC	APS, WALC
Citizens Ut.-Santa Cruz	AZ	CUCSC	4			WALC, Mexico	WALC, APS
Electric District No. 3	AZ					APS	APS
Electric District No. 7	AZ					APS	APS
Navajo Tribal Ut. Auth.	AZ, NM, UT	NTUA				APS, UPLC, WAUC	APS, WAUC, UPLC, PSN
Navopache Elec. Coop.	AZ, NM					APS	APS
Papago Tribal Ut. Auth.	AZ					APS	APS
Wickenburg	AZ					APS	APS
Yuma Axis Plant	AZ		75			IID, APS	(None)
Bureau of Reclamation-Lower Colorado	AZ, CA	USLC	525[13]		WALC		(None)
Imperial Irrig. Dist.	CA	IID	391	340	WALC, APS, SCE		WALC
Morenci Water & Elec. Co.	AZ			8			Phelps Dodge
Salt River Project	AZ, CO	SRP	4,038	1,877	APS, WALC, WAUC LDWP, TGE, AEPC	USBIA-San Carlos	APS, WALC, WAUC PSNM, PSC, SCE, LDWP, NEVP, COUE PSPL, PEGT
Tucson Electric Power Co.	AZ, NM	TGE	864	838	APS, PSNM	Trico	WALC
Western Area Power Admin.-Lower Colorado	AZ, CA NV	WALC		576	USLC, APS, WAUC, SPR, TGE, APA, LDWP, NEVP, MWD	CUCSC, CUCMD, CUCLH	APS, USLC, WAUC, LDWP
Electric District No. 2	AZ					WALC	WALC
Electric District No. 4	AZ					WALC	WALC
Electric District No. 5	AZ					WALC	WALC
Mesa	AZ					WALC	WALC
Mohave Elec. Coop.	AZ					WALC	WALC
USBIA-Colorado R. Indian Agcy.	AZ					WALC	WALC
USBIA-San Carlos	AZ		10	46		ED-2, SRP	WALC

Wellton-Mohawk Irrig. & Dr. Dist.	AZ					WALC	WALC
Yuma County Water Users Assn.	AZ					IID, Mexico	WALC
Bureau of Reclamation - Elephant Butte	NM	USSW	24		PEGT, WASW		(None)
Western Area Power Admin. - S.W. Region	NM	WASW		5 (est.)	PEGT		USSW
Public Service Co. of New Mexico	NM	PNM	871	683	APS, COPS, PEGT, TGE, USAT, WAUC		EPE, PEGT, SRP, TGE
Gallup, City of	NM					PNM	PNM
U.S. DOE (Los Alamos)	NM	USAT	20	62	PEGT, PNM		PNM, WASW
Los Alamos County Util.	NM					USAT	USAT
Plains Elec. G&T Coop.	NM	PEGT	53	204	COPS, PNM, USAT, USSW		PNM, WASW
Central NM Elec. Coop.	NM					PEGT	PEGT
Columbus Elec. Coop.	NM					PEGT	PEGT
Continental Div. Elec. Coop.	NM					PEGT, PSNM	PEGT
Jemez Mountains Elec. Coop.	NM					PEGT	PEGT
Kit Carson Elec. Coop.	NM					PEGT	PEGT
Mora-San Miguel Elec. Coop.	NM					PEGT, PSNM	PEGT
Northern Rio Arriba Coop.	NM					PEGT	PEGT
Otero County Elec. Coop.	NM					PEGT	PEGT
Sierra Elec. Coop.	NM					PEGT	PEGT
Socorro Elec. Coop.	NM					PEGT	PEGT
Springer Elec. Coop.	NM					PEGT	PEGT
Raton Public Service Co.	NM	RATO	12	8(est.)		Springer Elec. Coop.	Springer Elec. Coop.
Springer, Town of	NM					Springer Elec. Coop.	Springer Elec. Coop.
Farmington, City of	NM	FATN	31	52		WAUC	WAUC Coop.
Aztec, City of	NM					FATN	WAUC
Truth or Consequences, City of	NM					PNM	WASW, WAUC
El Paso Electric Company	NM, TX	EPE	1,091	690	COPS, PNM, RIGE, USSW		PCO, SCE, USSW, UPLC
Rio Grande Electric Coop.	TX					CEPL, EPE, MECI, WETU, Comm. Fed. De Elec. Mexico	CEPL, EPE, MECI, WKT
Community Pub. Service Co.	NM	COPS	55	100	EPE, PEGT, PNM, USSW		EPE, PNM

Electric Power Characteristics
Northern California-Nevada Power Area

Name of Utility	State	Code	Installed Capacity 1978 (MW)	Peakload 1978 (MW)	Major Interconnections[1]	Radial Interconnections	Purchases Power From
No. California-Nevada Power Area			16,910	16,024			
City & County of San Francisco	CA	CCSF	293		PGE, TUID, MOID		PG&E
CA State, Dept. of Water Res.	CA	CDWR	1,183[14]		PG&E, USMP		PG&E, LDWP, BPA
Pacific Gas & Electric Co.	CA	PG&E	11,100	12,971	PAPL, WAMP, SMUD CCSF, SCE, SPP, USMP, CDWR, MOID	EBMU, MEID, NEID, ORWI, PLWA, OASJ, UBA, TUID	EBMU, MEID, NEID SPP, ORWI, PLWA, OASJ, SDGE, YUBA, CDWR, CCSF
Alameda	CA					PG&E	PG&E
Bay Point Light & Power	CA					PG&E	PG&E
CP-National--Chester	CA	CPNL				PG&E	PG&E
CP-National--Westwood	CA	CPNL				PG&E	PG&E
CP-National--Weaverville	CA	CPNL				PG&E	PG&E
East Bay Municipal	CA	EBMU	15			PG&E	(None)
Healdsburg	CA					PG&E	PG&E
Lompoc	CA					PG&E	PG&E
Merced Irrigation Dist.	CA	MEID				PG&E	(None)
Nevada Irrigation Dist.	CA	NEID	61			PG&E	(None)
Oroville Wyandotte Irrig. Dist.	CA	ORWI	91			PG&E	(None)
Placer County Water Agency	CA	PLWA	211			PG&E	
So. San Joaquin & Oakdale	CA	OASJ	81			PG&E	(None)
Ukiah	CA					PG&E	PG&E
Yuba County Water Agency	CA	YUBA	331			PG&E	(None)
Bureau of Reclamation-Mid Pacific	CA	USMP	1,162[15]		WAMP		(None)
Western Area Power Admin.- Mid Pacific	CA	WAMP		208	PG&E, SMUD, PPL, USMP		USMP, BPA
Biggs	CA					PG&E	WAMP
Gridley	CA					PG&E	WAMP
Palo Alto	CA					PG&E	WAMP
Plumas Sierra Rural Elec.	CA, NV					PG&E	WAMP
Redding	CA					PG&E	WAMP
Roseville	CA					PG&E	WAMP, PG&E
Santa Clara	CA					WAMP	WAMP
Shasta Dam Area PUD	CA					WAMP	WAMP
Sacramento Municipal Util. Dist.	CA	SMUD	1,525	1,578	WAMP, PG&E		WAMP
Alex Brown Elec. Co.	CA					SMUD	SMUD
Sierra Pacific Power Co.	CA, NV	SPP	555	563	UPLC	PG&E, SCE, UPLC	PG&E, UPLC, SCE
CP-National, Winnemucca	NV	CPNL				SPP	SPP
Fallon	NV					SPP	SPP
Mt. Wheeler Power Co.	NV, UT				UPLC	SPP	SPP, ICPA, UPLC
Truckee Donner PUD	CA					SPP	SPP
U.S. Army Ammo Depot	NV		3			SPP	SPP
Pacific Pwr & Light (in CA only)	CA	PPL	67[16]	153[17]	PG&E		See NW Power Pool
Surprise Valley Electrific Corp.	CA, OR, NV					PPL	BPA, IPC
Turlock-Modesto Irrig. Dist.	CA	TUID, MOID	140	550	CCSF, PG&E		CCSF
Carlin	NV		3	1		(None)	(None)

Electric Power Characteristics
Southern California-Nevada Power Area

Name of Utility	State	Code	Installed Capacity 1978 (MW)	Peakload 1978 (MW)	Major Interconnections[1]	Radial Interconnections	Purchases Power From
So. California-Nevada Power Area			24,039	20,890			
Burbank	CA	BURB	272	197	LDWP		BPA, WALC, WPA, NEVP, LDWP, IPC, EUGE, BCHA
CA State Dept. of Water Resources	CA	CDWR	120[18]		SCE		PG&E, LDWP, BPA
Glendale Public Service	CA	GLEN	306	195	LDWP		WALC, BPA, NEVP, BCHA, EWEB, IPC SCL, LDWP
Los Angeles, Dept. of Water & Power	CA, NV	LDWP	5,034	4,144	SCE, APS, BPA, NEVP, BURB, PASA, SRP, GLPS, WALC		BPA, WALC, BPH, SCE, APS, SRP
Metrop. Water Dist. of So. CA	CA, NV	MWD		327	SCE, WALC		WALC
Nevada Power Co.	NV	NEVP	786	1,254	SCE, LDWP, WALC, SRP	Valley Elec. Assn., NV-Colo. R.R.	SCE, SRP, WALC, LDWP
CP-National, Needles-Searchlight	NV	CPNL				NALC	NEVP
Lincoln County Pwr. Dist.	NV	LCPD				NEVP	NEVP
Alamo Power Dist.	NV					LCPD	LCPD
Caliente Pub. Ut.	NV					LCPD	LCPD
Farmers Mutual	NV					LCPD	LCPD
Panaca Power & Light	NV					LCPD	LCPD
Pioche Pub. Lt.	NV					LCPD	LCPD
Penoyer Valley Elec.	NV					LCPD	LCPD
Overton Power Dist.	NV					NEVP, Dixie-Escalante REA	NEVP
State of NV, Colorado River Resources	NV					NEVP, WALC	WALC
Valley Elec. Association	CA, NV					WALC, SCE, NEVP	WALC, SCE
Pasadena, Main	CA	PASA	301	191	SCE		BPA, BCHA, NEVP, SCL, TACO, PG&E, SRP, EWEB, PSPL, IPC, MPC
Pasadena, Azusa P.P.	CA		3			SCE	SCE
Southern Calif. Edison Co. -Main	CA, NV	SCE	13,626	12,022	PG&E, LDWP, WALC, NEPC, SRP, APS, TGE, PSNM, SDGE, CDWR	PASA, IID	BPA, APS, IPC, MPC, PG&E, PPL, PGE, PSPL, PSNM, SDGE, SPP, UPLC, WWPC, CDWR
Anaheim	CA					SCE	SCE
Anza Elec. Coop.	CA					SCE	SCE
Azusa	CA					SCE	SCE
Banning	CA					SCE	SCE
Boulder City,	NV					SCE, WALC	WALC
Colton	CA					SCE	SCE
Riverside	CA					SCE	SCE

Electric Power Characteristics
Southern California-Nevada Power Area (Continued)

Name of Utility	State	Code	Installed Capacity 1978 (MW)	Peakload 1978 (MW)	Major Interconnections[1]	Radial Interconnections	Purchases Power From
So. Calif. Edison Co., Blythe	CA					APS, WALC	WALC
So. Calif. Edison Co., Santa Catalina	CA		6	3		(None)	(None)
So. Calif. Water Co.	CA					SCE	SCE
Vernon	CA					SCE	SCE
San Diego Gas and Electric	CA	SDGE	2,402	1,981	SCE		BPA, SCE, BCHA, PG&E, SARV, DCWR, IID, WKPL
Escondido Mutual Water Sys.	CA		8			SDGE	SDGE
Bureau of Reclamation--Lower Colo.	AZ, CA, NV	USLC	1,175[19]	576	WALC, SCE, LDWP, MWD	CPNL	(None)

Electric Power Characteristics
Rocky Mountain Power Area

Name of Utility	State	Code	Installed Capacity 1978 (MW)	Peakload 1978 (MW)	Major Interconnections[1]	Radial Interconnections	Purchases Power From
Rocky Mountain Power Area							
Central Tele. & Utils. (SCPD)	CO	CETU	106	180	CULA, PSC, WAUC		CCS, PSC, WAUC
La Junta Mun. Util.	CO	LAJU	19	13		CETU	CETU
Lamar, City of, Util. Co.	CO	LALP	35	21		CETU	CCS, PSC, WAUC
Granada, Town of	CO					LALP	LALP
Holly Mun. Elec.	CO					LALP	LALP
Las Animas Mun. Lt. & Pwr.	CO	LAAN	6	5		CETU	CETU
Colorado Springs, City of	CO	CCS	351	294	PSC, WAUC		WAUC
Fountain Light Dept.	CO					CCS	CCS
Colorado-Ute Elec. Assn.	CO	CUEA	522	411	MOLE, PRPA, PSC, PSNM, WAUC, TSGT		PSC, WAUC
Aspen, City of	CO					CUEA	PSC
Delta-Montrose Elec. Assn.	CO					CUEA, City of Delta	CUEA
Delta, City of	CO		5			Delta-Montrose Elec.	Delta-Montrose, WAUC
Empire Elec. Assn.	CO					CUEA	CUEA
Grand Valley Rural Pwr.	CO					CUEA	CUEA
Gunnison County Elec.	CO					CUEA, City of Gunnison	CUEA
Gunnison, City of	CO					Gunnison County Elec., WAUC	Gunnison County, Elec. WAUC
Holy Cross Elec. Assn.	CO					CUEA, PSC	CUEA
La Plata Elec. Assn.	CO					CUEA	CUEA
San Isabel Elec. Services	CO					CUEA	CUEA
Trinidad, City of	CO	TRIN	11	7		San Isabel Elec. Servs.	San Isabel Elec. Serv.
Walsenburg, City of	CO					San Isabel Elec. Servs.	San Isabel Elec. Serv.
San Luis Valley Rural Elec. Coop. Inc.	CO					CUEA, PSC	CUEA
San Miguel Pwr. Assn.	CO					CUEA	CUEA
Sangre DeCristo Elec. Assn.	CO					PSC	CUEA
Southeast Colo. Pwr. Assn.	CO					CUEA	CUEA
Springfield, City of	CO					S.E. Colo. Pwr. Assn.	S.E. Colo. Pwr. Assn.
White River Elec. Assn.	CO					CUEA	CUEA
Yampa Valley Elec. Assn.	CO					CUEA	CUEA
Oak Creek, Town of	CO					Yampa Va. Elec. Assn.	Yampa Va. Elec. Assn., WAUC
Public Service Co. of Colo.	CO	PSC	2,924	2,536	CETU, CCS, CUEA, TSGT, WAUC		CCS, PPL, PRPA, TGE
Burlington Mun. Lt. & Pwr.	CO	BURN	8	5		TSGT	PSC, WALM
Center Mun. Elec. Lt. & Pwr.	CO					PSC	WAUC
Denver, City & County of	CO	DENV	3	3		PSC	PSC
Frederick, City of	CO					WALM, Union REA	WALM, Union REA
Glenwood Springs Elec. Sys.	CO					PSC	PSC

Haxtun Mun. Lt. & Pwr.	CO						WALM	WALM
Holyoke Mun. Pwr. & Lt.	CO						WALM	PRPA
Longmont, City of	CO						WALM	PRPA
Loveland Lt. & Pwr.	CO						WALM	WALM
Lusk, Town of	WY						WALM	WALM
Pine Bluffs, Town of	WY						WALM	WALM
Torrington, Town of	WY						WALM	WALM
Wheatland, Town of	WY						WALM	PPL
Platte River Power Authority	CO						WALM	WALM
Cheyenne Lt., Fuel & Pwr.	CO	CHLF	13	69			WALM	WALM
Consumer Lt. & Pwr.	WY						PPL	PPL
Willwood Lt. & Pwr.	WY						PPL	PPL
Basin, Town of	WY						PPL	PPL
Deaver, Town of	WY						PPL	PPL
Powell Mun. Elec. Dist.	WY						PPL	PPL
Sviler Lt. & Pwr.	WY						PPL	
No. Washakie REA	WY						Upton, Gillette,	
So. Washakie REA	WY						Tri-County Elec. Assn.,	
Black Hills Pwr. & Lt. Co.	SD, WY	BLHP	237[22]	182	WALM, PPL, TSGT, NEPP		Butte Elec. Coop.,	
							Blk. Hills Elec. Coop.	Rushmore Elec.
							BLHP	BLHP
							BLHP	BLHP
							BLHP	BLHP
Tri-County Electric Assn.	WY			16			BLHP	USLM
Gillette	WY			1			Alliance, Sidney	
Upton	WY			950[23]	USLM, CHLF, PPL, MPC, COSP, NEPP, PRPA, TSGT			
Western Area Power Admin. Lower Missouri Region	WY, CO, SD, MT	WAUC			PSC, WAUC, BLHP, USUM			
Western Area Power Admin. Upper Colorado Region	CO, AZ NM, UT, WY	WAUC		184	USUC, APS, CETU, CUEA, ELPE, MOLE, PFL, PLEG, PCS, PSNM, SRP, SCE, TSGT, TGE UPLC, WAUC, WALM	FATN, NAUA		USUC

Electric Power Characteristics
Rocky Mountain Power Area (Continued)

Name of Utility	State	Code	Installed Capacity 1978 (MW)	Peakload 1978 (MW)	Major Interconnections[1]	Radial Interconnections	Purchases Power From
Julesburg, Town of	CO					Highline Elec. Assn.	PSC, Highline Elec.
Lyons Elec. Dept.	CO					PSC	PSC
Home Lt. & Pwr. Co.	CO					PSC	PSC
Intermountain REA	CO					PSC	PSC, WALM
Mountainview Elec. Assn.	CO					K.C. Elec. Assn..	K.C. Elec. Assn.
						PSC, TSGT	Assn., TSGT
Redlands Water & Power	CO					PSC	PSC
Union Rural Elec. Assn.	CO					PSC, WALM	TSGT
Tri-State G&T Assn.	CO	TSGT	310	NA	CUEA, PRPA, PSC, SRP, WALM, WAUC		BAEP, CCS, WALM
Big Horn Rural Elec. Coop.	WY					WALM	PPL, TSGT
Carbon Power & Light	WY					WALM	TSGT
Garland Light & Power	WY					WALM	TSGT
Highline Elec. Assn.	CO					WALM	TSGT
Hot Springs County REA	WY					PPL, TSGT, WALM	TSGT
K.C. Elec. Assn.	CO					TSGT, WALM	TSGT
Morgan County REA	CO					WALM	TSGT
Mountain Parks Elec.	CO					WALM	TSGT
Mountain View Elec.	CO					K.C. Elec. Assn., TSGT	K.C. Elec. Assn., TSGT
						WALM	TSGT
Niobrara Elec. Assn.	WY					WALM	TSGT
Poudre Valley REA	CO					TSGT, WALM	TSGT
Riverton Valley Elec. Assn.	WY					WALM	TSGT
Rural Elec. Company	WY					MODU, PPL	TSGT
Sheridan-Johnson REA	WY					WALM	TSGT
Shoshone River Power	WY					Shoshone River Pwr.	TSGT, WALM
Cody, City of	WY					WALM	TSGT
Wheatland Rural Elec. Assn.	WY					WALM	TSGT
Wyrulec Company	WY					WALM	TSGT
Fort Laramie, Town of	WY					WALM, Wyrulec Co.	WALM
Lingle, Town of	WY					WALM, Wyrulec Co.	WALM
Y-W Elec. Assn.	CO					SOPE, TSGT, WALM	TSGT, WALM
Wray Mun. Lt. & Pwr.	CO					Y-W Elec. Assn., WALM	TSGT
Yuma, Town of	CO					Y-W Elec. Assn., WALM	WALM
Bureau of Reclamation	CO, WY,	USLM	644[20]		WALM, PPL, MPC		(None)
--Lower Missouri River	MT						
Bureau of Reclamation	CO, AZ,	USUC	1,290[21]		WAUC, APS, PPL, UPLC	GAPA	(None)
--Upper Colorado River Storage	UT						
Proj. Estes Park, Town of	CO					WALM	PRPA
Fleming, Town of	CO					WALM	WALM
Fort Collins Lt. & Pwr.	CO					WALM	PRPA
Fort Morgan, City of	CO					WALM, Morgan County, REA	WALM, Morgan City, REA
Guernsey, Town of	WY					WALM	WALM

[1]See discussion on Planned Major Interconnections.
[2]WSCC Area less Canadian Systems (BCHA, page 3, WKPL, page 6).
[3]Two 500-kV BPA lines to BCHA at Custer WA; one 230-KV BPA line at Boundary, WA to BCHA Nelway Sub in Canada.
[4]One 230-kV BPA line at Boundary, WA to WKPL Substation at Waneta, Canada.
[5]WSCC member system.
[6]Not included in totals for Western Region and Northwest Power Area shown on page 1.
[7]USBR-Plants, Sched. 1, BPA-Main Sys. + BPA-So. ID + Provo R. Project + Rogue R. Project.
[8]BPA-Main Sys., Form 12, Sched. 1.
[9]1978 Form 12, Sched. 1 WA-OR-CA: 2,293.8 MW
WY 2,557.1 " (incl. 80% of Wyodak - 265.5 MW)
MT 28.0 "
4,878.9 "
Less plants in No. CA -67.2 "
Total in NW Power Pool 4,811.7 "
[10]Integrated peak for OR, WA, WY, MT, ID, CA, 1978 Form 1, P. 431: 3,659.7 MW
Less peak demand for CA, 1978 Form 12, Sched. 17, line 13 -152.9 "
1978 peak demand for PAPL in NW Power Pool 3,506.8 "
[11]WSCC member system.
[12]Canyon Ferry Project.
[13]Davis P.P. 240 MW, Parket P.P. 120 MW, Hoover Units A3, A4 - 165 MW.
[14]G. Hyatt - 644.3 MW + Thermalito - 115.1 MW + San Luis - 424.0.
[15]Central Valley Projects, + O'Neill, + Lewiston.
[16]1978 Form 12, Sched. 1, Main Sys. for PNW, CA plants. See also notes for PaPL, NW Power Pool.
[17]1978 Form 12, Sched. 17, Main Sys. for PNW, Line 13.
[18]Devil Canyon.
[19]Hoover Units A1, A2, A5, A6, A7, A9, N1, N2, N3, N4, N5, N6, N7.
[20]Alcova 36.0 MW, Big Thompson 4.5 MW, Boysen 15.0 MW, Estes 45.0 MW, Flatiron 71.5 MW, Fremont Canyon 48.0 MW, Glendo 24.0 MW, Green Mountain 21.6 MW, Guernsey 4.8 MW, Heart Mountain 5.0 MW, Kortes 36.0 MW, Mary's Lake 8.1 MW, Cole Hill 33.3 MW, Seminoe 32,4 MW, Shoshone 6.0 MW, Williams Fork 3.0 MW, Yellowtail 250.0 MW.
[21]Glen Canyon 950 MW, Flaming Gorge 108 MW, Blue Mesa 60 MW, Morrow Point 120 MW, Crystal 28 MW, Fontenelle 10 MW, Upper Molina 9 MW, Lower Molina 5 MW
[22]Ben French 76.0 MW
Kirk 31.5 MW
Neil Simpson 27.7 MW
Osage 35.5 MW
20% of Wyodak 66.4
237.1 MW
[23]875 MW - peakload reported by WALM for 1978.
75 MW - estimated load served from Yellowtail Project.
950 MW

NOTE: In most cases the municipal utility systems listed are identified in abbreviated form by the name of the community rather than the full name of the utility system.

POWER TRANSFERS BETWEEN WSCC AND MARCA

MARCA and the WSCC Region are directly interconnected through an a-c/d-c/a-c tie at the Stegall Substation in Nebraska where bulk power transfers of up to 100 MW of power in either direction could be achieved. Transmission of bulk power over existing a-c lines that connect systems in both areas is not feasible because of inadequate capacity of the lines and instability problems that would arise if interconnected operations were attempted. However, another means of power exchange between the two council areas is possible by transferring the output of generating units at plants located on the a-c separation points.

In southern Montana, within the Western Region, is the Water and Power Resources Service's Yellowtail Hydroelectric project with four 62.5-MW units. Normally, the generated output from two units is used for serving loads within the Western Region. However, in case of need, the output from the other two units at the project can also be made available for transfers to the WSCC area. The amount of power for serving eastern loads is then replaced by surplus power in the Billings area that has been purchased through the control center at Watertown, S.D., of the Pick Sloan-Missouri Basin Program Eastern Division

A similar arrangement for transmitting power either westward or eastward can be accomplished by switching the output of some of the generating units at the Corps of Engineers' Fort Peck Hydroelectric Station in northern Montana. The project has five generating units: two units at 35 MW; two units at 40 MW; and one unit at 15 MW. Under normal conditions, the plant operation is split to serve both western and eastern loads. In case of need, all of the units, along with a small amount of local load, can be switched to serve loads within the MARCA Region. The missing power for serving western loads is then made up from excess power that has been purchased when available and retained in storage in the Pick Sloan-Missouri River Program hydroelectric projects.

Basin Electric Power Cooperative is constructing--as part of the Missouri Basin Power Project--the Laramie River Station, consisting of three 500-MW net steam electric coal-fired generating units located in southeastern Wyoming near the town of Wheatland. Two units will always transmit power westward for loads within the Western Region (WSCC). These units will be under the control of the WAPA control center at Flatiron, Colo. The third unit will always transmit power eastward to serve loads within the MARCA area, and will be under WAPA's control center at Watertown, S.D.

There are no major transmission lines interconnecting the adjoining Western System Coordination Council area and MARCA, nor are there any transmission lines being planned. The Laramie River Station, therefore, will have two separate 345-kV switching stations, one connected to the WSCC area and one connected to the MARCA area. These switching stations are designed so that if the east generating unit or one of the west generating units are out of

service for an extended period of time, a west or east generating unit can be connected to the switching station that has a unit out of service. This design was developed for the possibility of a loss of a generating unit for an extended period of time and when replacement power could not be located in that area. Because of transmission limitations, the eastern (MARCA) area can only receive power from one 500-MW unit, and the western (WSCC) area can only receive power from two 500-MW units. Therefore, the Laramie River Generating Station does not have the capability of unilaterally switching generating units to the area which is temporarily short of power.

There are no interconnections between the adjoining Western System Coordinating Council area and Southwest Power Pool areas, nor the Western System Coordinating Council area and the Electric Reliability Council of Texas areas.

PROPOSED BULK POWER TRANSMISSION LINES

Following is a list of additional 500-kV and 345-kV bulk power lines being proposed in the Western Region.

345-kV Lines

Utility	From	To	Miles	Expected Service Date
Colorado Ute Electric Association	Cahone, CO	San Juan, NM	104	10-82
	Rifle, CO	Delta, CO	90	10-82
	Delta, CO	Cahone, CO	111	10-82
	Craig, CO	Rifle-CUEA, CO	83	10-82
El Paso Electric Company	Newman Sub, TX	Caliente Sub, TX	40	5-83
	Greenlee, AZ	Hidalgo Sub, NM	58	4-84
	Hidalgo Sub, NM	Luna Sub, Deming, NM	49	4-84
	Luna Sub, Deming, NM	Rio Grande Sub, NM	86	4-84
	Newman Sub, TX	Rio Grande Sub, NM	40	4-84
	Pajarito, NM	Alamogordo, NM	130	5-88
	Alamogordo, NM	Caliente, TX	126	5-88
Idaho Power Company	Kinport, ID	Midpoint, ID	105	10-81
Nevada Power Company	Warner, UT	Allen, NV, 2 lines	87	6-85
	Warner, UT	Glen Canyon, AZ	126	6-86
Public Service Co. of Colorado	Basalt, CO	Malta, CO	47	10-81
	Southeastern, CO	Waterton, CO	228	5-85
	Southeastern, CO	Smoky Hill, Denver, CO	200	5-86
Public Service Co. of New Mexico	San Juan-West Mesa, NM	B-A Algodones, NM	48	12-80
	Norton, NM	B-A Station, NM	43	12-82
	Ojo, NM	Norton, NM	26	12-82
	Pajarito, NM	Sandia Sub, NM	25	5-85
Sierra Pacific Power Company	Valmy, NV	Humboldt, NV	102	5-80
	Humboldt, NV	NV-ID border	70	5-80
	Oreana, NV	Valmy, NV	73	5-80
	Tracy, Reno, NV	Oreana, NV	86	5-80
	Valmy, NV	Tracy, Reno, NV	159	10-81
	Tracy, Reno, NV	Mira Loma, Reno, NV	16	10-81
	Tracy, Reno, NV	Spanish Springs, NV	14	6-82
	Spanish Springs, NV	Valley Road, NV	6	6-82
	Fort Churchill, NV	Buckeye, NV	38	10-83
	Mira Loma, Reno, NV	Brunswick, NV	25	10-87
	Brunswick, NV	Buckeye, NV	16	10-87
	Mira Loma, NV	Mt. Rose, NV	24	6-89
	Valmy, NV	Austin, NV	96	10-89
Tri-State Generation & Transmission	Laramie R. Station, WY	Archer, Cheyenne, WY	75	3-80
	Archer, Cheyenne, WY	Story, Brush, CO	100	6-80

345-kV Lines (Continued)

Utility	From	To	Miles	Expected Service Date
	Laramie R. Station, WY	Ault, CO	110	8-81
	Laramie R. Station, WY	Story, Brush, CO	175	4-82
Tucson Electric Power Company	San Juan, NM	McKinley, Gallup, NM	90	4-81
	McKinley, Gallup, NM	Springerville Tap, Red Hill, NM	95	4-81
	Springerville Tap, Red Hill, NM	Springerville, AZ	12	4-81
	Springerville, AZ	Coronado, AZ	22	4-82
	Springville Tap, Red Hill, NM	Greenlee, Clifton, AZ	100	4-83
	Springerville, AZ	Springerville Tap, Red Hill, NM	12	4-83
	Springerville Tap, Red Hill, NM	Greenlee, Clifton, AZ	100	4-85
	Springerville, AZ	Springerville Tap, Red Hill, NM	36	5-85
	Tortolita, Red Rock, AZ	South, Tucson, AZ	100	5-86
Utah Power & Light Company	Camp Williams, UT	Terminal, UT	26	4-82
	Ben Lomond, UT	Borah, ID	125	6-82
	Emery, UT	Camp Williams, UT	124	2-83
	Sigurd, UT	Glen Canyon, AZ	59	6-85
	Desert, UT	Mona, UT	185	9-85
	Intermountain, UT	Mona, UT	82	2-86
	Camp Williams, UT	Mona, UT	48	2-86

500-kV Lines

Utility	From	To	Miles	Expected Service Date
Arizona Public Service Company	Palo Verde, AZ	Yuma, AZ	115	5-84
	Palo Verde, AZ	Saguaro Plant, AZ	122	5-86
Bonneville Power Administration	Ashe, WA	Slatt Sub, OR, 2 lines	71	9-80
	Slatt Sub, OR	Marion, OR, 2 lines	155	9-80
	Buckley, OR	Malin, OR	232	10-82
	C. W. Paul Sub, WA	Satsop, WA	45	10-82
	G. H. Bell Sub, WA	Hot Springs, MT	165	8-84
	Garrison, MT	Hot Springs, MT, 2 lines	122	8-84
	Olympia, WA	Satsop, WA	27	6-86
	Shelton Tap, Olympia, WA	Shelton, WA	14	10-86
	Monroe, WA	Snoking Sub, WA	21	10-87
	Monroe, WA	P. J. Raver Sub, WA	42	10-87
	Santiam, OR	Conser Sub, Albany, OR	46	10-88
	Naneum, WA	Hanford, WA	55	10-88
	Slatt Sub, OR	John Day, OR, 2 lines	29	10-89
	John Day, OR	Big Eddy, OR, 2 lines	19	10-89
	Buckley, OR	Summer Lake, OR	156	10-89
	McNary, OR	LaGrande, OR	83	After 1989
Idaho Power Company	Brownlee, ID	LaGrande, OR	89	Late 1980
Los Angeles Department of Water and Power	Victorville, CA	Rinaldi, CA	95	3-80
	McCullough, NV	Victorville, CA Line No. 2	158	3-80
Montana Power Company	Colstrip, MT	Broadview, MT	112	9-83
	Broadview, MT	Townsend, MT, Line No. 2	138	9-83
	Broadview, MT	Townsend, MT, Line No. 1	138	9-83
Nevada Power Company	Allen, NV	El Dorado, NV, 2 lines	65	6-86
Pacific Gas and Electric Co.	Gates, CA	Gregg, CA	52	5-83
	Tesla, CA	Montezuma, CA	34	5-86
	Malin, CA-OR border	Montezuma, CA	289	5-88
Pacific Power and Light Co.	Midpoint, ID	Summer Lake, OR	369	9-81
	Summer Lake, OR	Malin, OR	75	9-81
Public Service Co. of New Mexico	Four Corners, NM	Ambrosia, NM	103	4-83
	Ambrosia, NM	Pajarito, NM	72	4-83
Salt River Project	Palo Verde, AZ	Westwing, AZ	45	6-80
	Palo Verde, AZ	Kyrene, AZ	75	9-82

500-kV Lines

Utility	From	To	Miles	Expected Service Date
San Diego Gas & Electric Co.	Imperial Valley, CA	Miguel, CA	82	5-84
Southern California Edison Co.	Lugo, CA	Mira Loma No. 3, CA	36	6-80
	Palo Verde, AZ	Devers, CA	240	5-82
	Devers, CA	Valley, CA	40	6-84
	Serrano, CA	Valley, CA	39	6-84
	Lucerne Valley, CA	Lugo No. 1, CA	48	1-85
	Mira Loma, CA	Serrano, CA	19	6-85
Tucson Electric Power Company	Tortolita, Red Rock, AZ	Saguaro, Red Rock, AZ	1	4-81
	Saguaro, Red Rock, AZ	Tortolita, Red Rock, AZ	1	5-86
Utah Power & Light Company	Wellington, UT	Camp Williams, UT	120	6-88
	Wellington, UT	Emery, UT	30	6-88

APPENDIX B

COMMENTS FROM INVITED REVIEWERS

APPENDIX B
COMMENTS FROM INVITED REVIEWERS

The following organizations provided comments on a review draft of this report as requested by letter of August 10, 1980, from the Director, Office of Electric Power Regulation, Federal Energy Regulatory Commission:

- Colorado Public Service Commission
- Department of Energy, Economic Regulatory Administration, Office of Utility Systems
- Department of Energy, Western Area Power Administration
- Department of Energy, Resources Applications, Office of Power Marketing Coordination
- Edison Electric Institute
- National Rural Electric Cooperative Association
- Western Systems Coordinating Council

The following were also invited to comment:

- Public Utility Commissions of Arizona, California, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming
- National Association of Regulatory Commissioners
- American Public Power Association

This Appendix includes comments received from invited organizations through October 21, 1980.

STATE OF COLORADO

THE PUBLIC UTILITIES COMMISSION
Department of Regulatory Agencies

500 State Services Building
1525 Sherman Street
Denver, Colorado 80203

Richard D. Lamm,
Governor

Gail H. Klapper,
Executive Director

COMMISSIONERS:
Edythe S. Miller,
Chairwoman

Daniel E. Muse
L. Duane Woodard

Harry A. Galligan, Jr.,
Executive Secretary

Administration (303) 839-3154
Transportation (303) 839-3171
Fixed Utilities (303) 839-3181
Counsel (303) 839-3188

September 23, 1980

Mr. William W. Lindsay, Director
Office of Electric Power Regulation
Federal Energy Regulatory Commission
Washington, DC 20426

Dear Mr. Lindsay:

As requested in your letter of August 19, 1980, our staff has reviewed the draft of a report on power pooling in the Western Region. The report accurately reflects our understanding of the current developments, and we have no recommendations for change. We note, however, that in Chapter 7, where members of the Western Conference of Public Service Commissions state their positions on regional coordination, there is no statement by the Colorado Public Utilities Commission. We have attached a position statement that we would hope can be included in the final report.

We would like to thank you for the opportunity to review the draft copy of this report.

Yours very truly,

Edythe S. Miller

EDYTHE S. MILLER
Chairwoman

ESM:dc

Attachment

RECEIVED
SEP 29 1980
DIV. OF ISA

POSITION STATEMENT OF THE

COLORADO PUBLIC UTILITIES COMMISSION

ON REGIONAL COORDINATION

The Colorado Public Utilities Commission regulates the rates and financing of investor-owned utilities, rural electric cooperatives and that portion of municipal utility service which is supplied outside the corporate limits of the city. The Commission also grants Certificates of Public Convenience and Necessity for the construction of major new facilities in the State. Recently the Legislature has given the Commission the responsibility to submit an energy report to the Legislature and to the Governor every two years. This report is to include a ten year forecast of loads and resources for all electric utilities in the State. This Commission has also begun to collect power plant productivity data as a means of monitoring the utilization of existing resources.

As a result of its on-going generic hearing on electric rate design, the Commission has had recent opportunity to consider the entire issue of regional coordination. Further hearings on this issue are in the process of being held. In its initial decision, however, the Commission has encouraged, to the maximum extent possible, coordinated planning and operations, and indicated that the degree of coordination will be considered in future energy cost adjustment hearings and in future applications for certificates of public convenience and necessity for the construction of new facilities. In that same decision, the Commission stated that it intends to avoid any actions which will encumber coordinated planning for bulk power resources by Colorado and non-Colorado utilities.

Department of Energy
Washington, D.C. 20461

September 26, 1980

Dr. William W. Lindsay
Director, Office of Electric Power Regulation
Federal Energy Regulatory Commission
Washington, D.C. 20426

Dear Dr. Lindsay:

The draft report on power pooling in the Western Region has been reviewed by the Office of Utility Systems (OUS). The report contains a useful account of the present status of power pooling in the region. The associated institutional setting in which these accomplishments have been achieved has also been well documented.

The discussion of regulatory and legislative impacts on regional coordination (pp. 154-161) is of interest, although its usefulness is somewhat diminished by the absence of statements from six States.

In an overview sense, OUS has problems with certain aspects of the report's characterization of impediments to coordination. The Executive Summary states that the principal impediment under utility control is the ability to cost justify additional coordination. The Summary identifies several regulatory impediments. The reader is therefore left with the impression that most coordination enhancement in the region must await regulatory improvements.

OUS believes utilities may be able to prudently proceed with significant coordination improvements without awaiting regulatory action. Also, a detailed cost benefit analysis is not always necessary. The WSCC's progress toward implementing an energy brokerage system is an example of such a strategy.

Specific improvements in the report with respect to matters under utility control might include:

- Identification of a program for resolving the nonregulatory impediments listed on page 163.

- The report is silent on the need for updating basic transmission agreements to cover firm and nonfirm transactions under multilateral agreements. Further, the report is silent on the need for transmission arrangements that are not in place but are perceived as necessary to many of the entities in the region. The need for discussion of this matter is evident in view of the amount of litigation in the region on the subject.

- Discussion of the specific scope, schedule and prospects of coordination studies referenced in the report. (e.g., the California studies referred to on pages 145 and 153).

- Prospects for implementation of a superbroker concept (e.g., a subregional approach to matching buyers and sellers of firm and non-firm power.)

- Improvements in analytical techniques to reduce uncertainty when evaluating coordination enhancement options.

The following comments might also be useful in improving the report.

- (p. 1) The statement at the end of the second paragraph that extensive interconnection permits the entire region to operate in a coordinated fashion is misleading. As mentioned elsewhere in the report there are many local transmission and operating constraints that prevent complete coordination.

- (p. 2) It is desirable to list as <u>examples</u> the enumerated economic benefits that have been achieved through pooling in the Western Region. This would avoid conveying the impression that each benefit shown is available throughout the region. For example all wheeling arrangements that could be in place are not in place in the case of Burbank, Glendale and Pasadena.

- (p. 2) OUS does not endorse the concept that the <u>principal</u> impediment to increased coordination lies in quantifying benefits with certainty. A number of additional impediments within utility control and of relatively <u>equal</u> stature exist. A number of such impediments are listed on page 163, including:

  - Reluctance to lose management autonomy in the interest of enhanced coordination.

- Competitive rivalry.

- Reaching agreement on an equitable distribution of costs and benefits among pool participants.

- (p. 8) Characterization of the generation mix in the RMPA as 51 percent thermal and 33 percent hydro does not seem consistent with the data presented on Table 1, p. 23.

- (p. 18) The report states that the power pool definition adopted by the Task Force includes both informal agreements between utilities and bilateral agreements that provide for coordinated planning and operations. The definition would also seem to apply to multilateral agreements and address planning and/or operations. However, OUS does not believe that full coordination is achievable in the absence of formal multilateral agreements covering planning and operations.

- (p. 18 and p. 22) The discussion of interconnection seems to imply that there are isolated utilities in the region. It would be useful to separately identify them and to assess the aspects for future interconnection of these systems.

- (p. 27) The report correctly states that no synchronous interconnection presently exists between the United States and Mexico. However it would be useful to add that numerous interconnections exist and to reference the availability of a detailed analysis in the recently completed study concerning electricity exchange between the United States and Mexico. (DOE/RG-033, Electricity Exchanges, United States/Mexico, May 1980.)

The Office of Utility Systems appreciates the opportunity to offer these comments.

Sincerely

Jerry L. Pfeffer
Assistant Administrator
for Utility Systems
Office of Utility Systems
Economic Regulatory Administration

RECEIVED
1980 OCT 20 AM 9:59
ELECTRIC POWER REGULATION

Department Of Energy

Western Area Power Administration
P.O. Box 3402
Golden, Colorado 80401

OCT 2 1980

IN REPLY
REFER TO: A6000

MEMORANDUM FOR DIRECTOR
OFFICE OF ELECTRIC POWER REGULATION
FEDERAL ENERGY REGULATORY COMMISSION
825 NORTH CAPITOL STREET, NE.
WASHINGTON, DC 20426

SUBJECT: REVIEW DRAFT OF POWER POOLING IN THE WESTERN REGION (Your Ltr to Dennis Eyre, 8/19/80, with copy to us)

We have reviewed the subject document with emphasis on those coordination and power pooling entities in which Western Area Power Administration (Western) is either a participant or is familiar with.

We believe the "External Review Draft" represents a good overview of the history, accomplishments, and problems facing the various coordination and power pooling entities in the Western region.

William H. Clagett
Deputy Administrator

cc:
Mr. Emerson Harper
Office of Power Marketing Coordination
Department of Energy
Mail Station 3344, Federal Building
12th and Pennsylvania Avenue, NW.
Washington, DC 20461

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OCT 20 1980
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ELECTRIC POWER REGULATION

OCT -7 1980

Department of Energy
Washington, D.C. 20461

Mr. William W. Lindsay
Director
Office of Electric Power Regulation
Federal Energy Regulatory Commission
Washington, DC 20426

Dear Mr. Lindsay:

This is in reply to your recent letter requesting our comments on the Commission's Western Region Task Force Report.

We have reviewed the report "Power Pooling in the Western Region" and suggest the changes indicated on the enclosed pages of the report.

We appreciate the opportunity to comment on the report and if we can further assist you in your studies, please feel free to contact my office.

Sincerely,

for Daniel M. Ogden, Jr.
Director, Office of Power
Marketing Coordination
Resource Applications

Enclosure

RECEIVED
OCT 10
DIV. OF ISA

JUSTIN KARP, Vice President

EDISON ELECTRIC INSTITUTE The association of electric companies

1111 19th Street, N.W.
Washington, D.C. 20036
Tel: (202) 828-7400

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OCT 6 1980
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1980 OCT -6 AM 9:17
ELECTRIC POWER REGULATION

September 29, 1980

Mr. William W. Lindsay
Director, Office of Electric
Power Regulation
Federal Energy Regulatory Commission
Washington, DC 20426

Dear Mr. Lindsay:

The Edison Electric Institute appreciates the opportunity to comment on the draft report on Power Pooling in the Western Region.

We believe that the report generally provides an accurate and informative description of existing modes of regional coordination and power pooling in the Western region.

The western region as defined in the report consists of four subregions. The subregions are, for the most part, informally organized and do not have common ownership or represent contractually connected entities. It is very difficult to assess the success of regional coordination over such a large and diverse region.

The report addresses the real, long-term, incremental benefits which are thought to be derived from pooling. Evaluating the dollar savings associated with the various benefits depends more on good engineering judgement than on precise economic analysis. The potential benefits from expanded data exchanges, brokerage systems, etc., will inevitably result in increased problems and costs to utilities. In the final analysis, we believe that increased interutility coordination is desirable only when it results in optimizing the cost and reliability of service from the viewpoint of consumers.

If the Edison Electric Institute can be of further assistance, please contact Fred Denny, our Director of Engineering, who was involved in reviewing the report and preparing our comments.

Sincerely yours,

Justin Karp

cc: John J. Kearney
Fred I. Denny

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1980 SEP 23 PM 2:26

NRECA NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
1800 Massachusetts Avenue, N.W.
Washington, D.C. 20036/202-857-9500

September 17, 1980

Mr. William W. Lindsay, Director
Office of Electric Power Regulation
Federal Energy Regulatory Commission
Washington, D.C. 20426

Dear Mr. Lindsay:

This will acknowledge receipt of your letter of August 19th and the enclosed report "Power Pooling in the Western Region" which was prepared by the Western Region Task Force.

Inasmuch as the National Rural Electric Cooperative Association (NRECA) had one or more representatives participating in the preparation of this report, we plan to withhold our comments until we are asked to review the combined report of all the regions which is to be prepared by the Commission.

Thank you for sending this material to us which we will use as backup material when we review the Commission's drafted report.

Sincerely,

Robert D. Partridge
Executive Vice President
and General Manager

RDP/ajl

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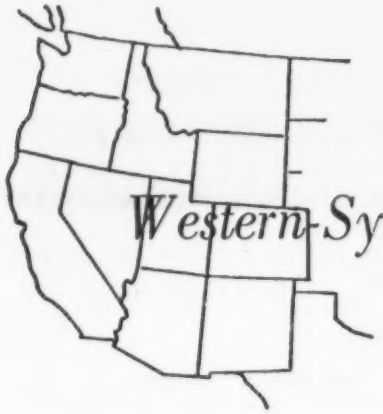
SEP 24 1980
DIV. OF ISA



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DIV. OF ESA

Western Systems Coordinating Council

DENNIS E. EYRE
ADMINISTRATIVE MANAGER
UNIVERSITY OF UTAH RESEARCH PARK
540 ARAPEEN DRIVE, SUITE 203
SALT LAKE CITY, UTAH 84108
TEL.: (801) 582-0353

September 29, 1980

Mr. William W. Lindsay
Director, Office of Electric
Power Regulation
Federal Energy Regulatory Commission
400 First Street, N.E.
Washington, D.C. 20426

Dear Mr. Lindsay:

We have reviewed the "External Review Draft" of the FERC report on Power Pooling in the western region. The report as drafted sets forth the unique characteristics of the region, the status of utility coordination and pooling, the impediments to additional coordination, the current activities to enhance coordination and some possible benefits which may accrue from additional coordination and pooling.

As cited in the report, the procedures and agreements which have been established for coordinating system operation and planning in the western region are justifiably numerous and in some instances overlapping. This complex process has been instrumental in providing the flexibility which is essential to enhancing subregional and regional coordination in an effective and timely manner. Unfortunately, it may appear to those unfamiliar with the advantages and benefits which have been realized using these procedures that this process lacks the formality necessary to achieve the proper level of coordination and pooling. It is essential that one understand the complex issues involved and recognize that the coordination process takes time and evolves based on economic incentives. It is also important to recognize that historically the industry has continually assessed the benefits of increased coordination and pooling and, where economically justifiable, has taken steps to enhance system operation and the system planning process.

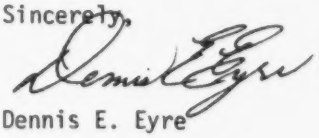
As noted in the report, the principal impediment to increased subregional and regional coordination is the difficulty in identifying additional benefits with sufficient certainty to justify the substantial expenditures which are often required. It is also noted that several

states have indicated a reluctance to use their resources (land, water and air) for the citing of new facilities which would serve other states. This philosophy will almost certainly hinder efforts to enhance sub-regional and regional coordination. There is also a general belief that even if new facilities could be cost justified on a subregional and regional basis to enhance coordination, there is a very distinct possibility that the regulating agencies may become the principal impediment.

With regard to our editorial comments on the report, I have taken the liberty of forwarding these comments under separate cover to Mr. Neblett of the San Francisco office.

We thank you for the opportunity to review the draft of this report and commend Mr. Neblett and his staff for their work in drafting a report pertaining to a very complex process which has fostered coordination throughout a very large and diverse region encompassing all or portions of the 14 western states.

Sincerely,



Dennis E. Eyre

cc: WSCC Administrative Committee
W. I. Wheelock, FERC
E. Neblett, FERC

APPENDIX C
COMMENTS BY TASK FORCE MEMBERS

APPENDIX C
COMMENTS BY TASK FORCE MEMBERS

This Appendix includes letters from two task force members to further the discussion of a specific power pooling issue in the California-Nevada Power Area raised in Chapter 6. It also includes letters from other task force members commenting on the completed report and responding to comments of invited reviewers.

Northern California Power Agency
770 Kiely Boulevard • Santa Clara, California 95051 • (408) 248-3422

PHILIP G. MICHAELS
General Manager

January 14, 1980

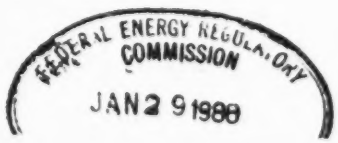
Mr. Eugene Neblett
Task Force Chairman
Federal Energy Regulatory Commission
555 Battery Street, Room 415
San Francisco, CA 94111

Dear Eugene:

We appreciate being given the opportunity to provide our comments in the form of constructive input to the completion of the Task Force report being filed by FERC, in compliance with the Public Utility Regulatory Policies Act. In general, we viewed the opportunity to sit down at the same table with public and private entities in the Western United States as a tremendous opportunity for coordination of our mutual goals and efforts in the areas of utility operations and planning. Before I get into the substantive remarks that I have regarding the efforts of this Task Force so far, I would like to assure you and the other participants in the Task Force that our comments are made in a very constructive way. Although they may be in strong language, it is only to emphasize the importance of the statements which we want to make and it is certainly not our intention to use this forum to argue any of the pending litigation points which are currently being heard before FERC and NRC.

The Northern California Power Agency (NCPA), having participated in the meetings of the Task Force, believes that our preliminary views at this early stage may be of some assistance to this Task Force in attempting to produce a final report by January, 1980. We recognized that representatives of Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) have been delegated the job of completing the details of the portion of the report relating to the California Power Pool, at least in the initial draft, but since NCPA's views of this matter are somewhat different than those of PG&E and SCE, we believe it would be prudent to state our position now.

This Task Force is participating in the study of power pooling pursuant to the directions of the Public Utility Regulatory Policies Act of 1978, Section 205(b), which direction is set forth in the draft Forward dated August 30, 1979 (REV. 9/5/79). Thus, the purpose of this study is to



examine the opportunities for conservation of energy, optimization in the efficiency of use of facilities and resources, and increased reliability through pooling arrangements. The draft Forward written by the FERC representatives states; "in effect, the Congress is inquiring whether there remain significant benefits available from voluntary coordination and power pooling not yet realized, or whether such benefits have already been attained to the degree practical."

The California Power Pool is a "voluntary power pool" which is, in many respects, not a "pool" at all within the ordinary understanding of the term which is normally embraced by the electric utility industry as a whole. Although the draft introduction to the Western Region Task Force Report on Power Pooling, at page 3, states that "The voluntary power pools work well during the routine operation of the system.", there are substantial questions in our mind as to how well the California Power Pool does work. It has appeared to NCPA, and others, that the California Power Pool serves essentially as a mechanism for coordination between the control areas of PG&E and SCE, with some benefits to the area of San Diego Gas & Electric Company. It does not appear that either the economic or the energy conservation advantages of coordinated operation are being taken advantage of, for example, nor are the use of facilities and resources being optimized even on a State of California basis, much less a West Coast basis.

In part, these deficiencies are a matter of perception. For example, virtually all of the generation in the PG&E control area is currently being dispatched and controlled on what presumably is an optimized basis by PG&E; the same is true for the SCE control area. Because of the fact that the California Power Pool is so structured as to be extremely financially disadvantageous, in its current form, to any entity smaller than the Los Angeles Department of Water and Power, and almost prohibitively forced separately to obtain from SCE or PG&E some substitute, in part, for the coordination and pooling services which should be available through the pool. This, in turn, forces these other entities to commit their generation as a practical matter to PG&E or SCE. Thus, while PG&E and SCE, may operate the generation within their control areas on a reasonably efficient basis, the benefits of that efficiency flow to PG&E and/or SCE, not to the owner of the facility. One of the effects of a pool structured in this fashion is effectively to preclude or substantially to hinder the construction and operation of new generation units by entities other than PG&E and SCE, except as PG&E or SCE may direct and permit.

Another deficiency, in our view, of the California Power Pool is the tendency, because of the penalties which are a part of the pool structure, to inhibit transactions between control areas. Studies have shown, for example, that the Western Area Power Administration (WAPA) Central Valley Project (CVP) generation resources could support over 1,200 megawatts of load, if WAPA were permitted to arrange for purchase of thermal energy from other entities in California or otherwise, during low water years. Because of contractual arrangement, however, WAPA is required to base its planning on the load that could be served by it, with each group of its units operating isolated, save only as PG&E may permit it to purchase limited amounts of power and energy from PG&E. While there is controversy as to what the number should be, it is our understanding that PG&E asserts it to be 554 MW. Even if the contractual restrictions which prevent WAPA from usefully obtaining energy

or capacity from others were dissolved, however, the penalties in the pool agreement would probably preclude any entity which is a pool member (other than PG&E) from selling energy or capacity to WAPA.

Obviously, since California is no longer a "hydro bound" state, similar relationships would probably be true for PG&E hydro capacity, yet capacity planning for the State of California is still being done by PG&E and SCE, each on a single control area basis, and without taking into effect the availability of thermal energy to permit hydro capacity to rise in the load curve so that the maximum capability of the hydroelectric installations may be utilized. If this were taken into account, much of the hydro available to the region could be utilized to obtain substantially greater useable capacity than appears now to be used for planning purposes.

In summary, there are at least two ways of looking at the adequacy of the California Power Pool, as it exists, within the terms of this Task Force study. The first approach, which is that which has been taken in the past by the pool members, is to examine the efficiency of operation of the existing units in each control area. Since both PG&E and SCE are very large as electric utilities go, are able to utilize sophisticated central dispatch systems and, in fact, have control over the generation of all other entities within their control areas, this approach could be expected to show reasonably efficient use of existing generation resources for each control area as a whole.

The second approach, which NCPA believes must be addressed, is to examine the California Power Pool in terms of its effects upon all of the entities filling a power-supply function in California, not just PG&E and SCE. NCPA believes that it would be irresponsible for this Task Force not to recognize the impediments which the California Power Pool imposes to the efficient use of California's natural and electrical resources, or the fact that the pool, as structured, creates substantial disincentive for all entities other than the pool members, in comparison to a pool agreement which would provide the more common pooling and coordination services which are not now available in California. 1/

1/ NCPA notes that in the draft form of Chapter 1 Status of Power Pooling in Western Region, the statement is made that "In the Western Region nineteen investor-owned utilities, eighteen municipal utilities, twelve public power systems, four federal agencies, three cooperatives, and one public utility district provide substantially all of the electric services." Those systems are located in Figure 2. Figure 2 reflects the member systems in the United States of the Western Systems Coordinating Council. NCPA notes that while certain of its municipal members are affiliates of the WSCC, NCPA itself is not on that list, yet is responsible for the approximately 800 MW of load served by its members. We believe it is misleading to use the WSCC list for this purpose, since there is very little advantage to being an affiliate member; few services and little information are available to affiliate members, although WSCC dues are still payable. Many entities thus do not belong.

NCPA, of course, reserves its rights to comment on the final draft of the report. We believe, however, that the views which we have expressed on the approach to be taken may be sufficiently different from those which may be stated by the drafters and that they should be placed before the Task Force at an early stage.

We have, during the past year, been negotiating with PG&E certain aspects of our business relating to wheeling and capacity reserves and we believe, based on the results of these negotations so far, that the anticipated contractual agreement will be fruitful to both NCPA and PG&E, and the Northern California area as a whole. Although the negotiations are not complete, we are confident that it will contain many fine points which will provide the basis for further improvements to the planning and operation of the entire California interconnected electric system. We hope that these efforts are just the beginning of reexamining and possibly modifying many major areas of operation and planning in California to the point that a power pool can be established to provide these benefits to its members which was the basic premise upon which the California Power Pool was first created. We hope this Task Force and the resulting work effort through the report will be able to help all entities achieve the goals and benefits of a good working power pool.

Yours truly,

Philip G. Michaels.

PHILIP G. MICHAELS
General Manager

cc: G. E. Shumard, Jr.
Task Force Members

PACIFIC GAS AND ELECTRIC COMPANY

PG and E

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H. R. PERRY
CHIEF TRANSMISSION PLANNING ENGINEER

November 25, 198(

Mr. Eugene Neblett
Regional Engineer
Federal Energy Regulatory Commission
333 Market Street, 6th Floor
San Francisco, CA 94105

Dear Mr. Neblett:

I have noted that the External Review Draft of the Western Region Task Force's report on "Power Pooling in the Western Region" has attached to it a letter submitted by NCPA commenting on an earlier draft of the Task Force report and criticizing aspects of the California Power Pool Agreement. None of the concerns and criticisms were ever expressed in the several meetings of the Task Force. Nevertheless, I can understand that the simpliest way for you to have these comments preserved is to include the letter in the Appendix to the report.

As is stated in the External Review Draft, various pooling issues presently are being addressed in the context of certain litigation involving both NCPA and PGandE. I do not believe that it is either necessary or appropriate for me in the context of the External Review Draft to address the merits of NCPA's comments. I wish to have noted, however, the fact that, while I will not comment on the substantive points in the NCPA letter and will not object to the inclusion of it in the report, I do take serious issue with many of the assertions made in that letter.

Sincerely,

H R Perry

Task Force Member
from Pacific Gas & Electric Company

FEDERAL ENERGY REGULATORY COMMISSION
NOV 26 1980

PNM PUBLIC SERVICE COMPANY OF NEW MEXICO
Post Office Box 2267 / Albuquerque, New Mexico 87103

November 24, 1980

Mr. Eugene Neblett
Federal Energy Regulatory
Commission
333 Market Street, 6th Floor
San Francisco, CA 94105

Dear Mr. Neblett:

Enclosed are marked-up pages indicating the few corrections to our report that I feel are needed.

Regarding ERA's comments I believe they all either are not applicable to New Mexico or represent a difference of opinion that does not require modification of our report.

It was good to see you again in Tucson.

Sincerely,

C D Bedford

C. D. Bedford
Vice President

CDB:lng
Enclosures

Public Service Company of Colorado

P. O. Box 840 Denver, Colorado 80201

November 25, 1980

Mr. Eugene Neblett
Federal Energy Regulatory Commission
333 Market Street, 6th Floor
San Francisco, California 94105

Dear Gene:

I concur completely with the plan of action contained in your letter of November 12, 1980, as to changes to finalize the report on "Power Pooling in the Western Region."

As to comment on the replies of External Reviewers, I believe that their suggestions are mainly in two categories when they suggest changes. In several cases it is evident that, due to unfamiliarity with the West, they lack understanding but is is doubtful that everything contained in a report would be without question. The second is one of perception of emphasis. As we have seen during the course of the pooling study, there are three main, but overlapping, reasons advanced for pooling: (a) Economic Savings, (2) Resource saving, and (3) Benefit to the Small Systems, and comments tend to be those items that the respondent wishes to stress and emphasize. Thus, while one may not agree with each, taken as a whole, they add to the understanding.

Both Mr. Hugo's and my final comment is to again commend you and your staff for an exceptional job on a difficult subject. You have taken the input from many diverse perspectives, fairly presented all sides and produced a report that says where we are, how we got there, the opportunities for the future, and the impediments, as viewed from the diverse facets of the industry, to the realization of these opportunities. The industry, its regulators, and its customers will all benefit from better understanding and the opportunities to work together to realize some of those opportunities which, on further study, are found to be obtainable.

We again thank you for the opportunity to work with you.

Yours truly,

Julian

Julian Reed Hayden
Manager of System Operations

JRH:r

cc: Dennis Eyre
Western Region Task Force
Bob Hugo

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